Northeast Power Coordinating Council

Reliability Assessment

For

Winter 2008-09

Conducted by the

NPCC CO-12 Working Group

November 2008
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1. Executive Summary

This report focuses on the assessment of reliability within NPCC for the 2008-09 Winter Operating Period. Portions of this report are based on work previously completed for the NPCC Reliability Assessment for the winter 2007-08\(^1\).

The NPCC Operations Planning Working Group (CO-12) works closely with the representatives of the NPCC CP-8 Working Group to ensure results are based on consistent data and modeling assumptions between the two studies.

Those aspects that the CO-12 Working Group has examined to determine the reliability and adequacy of NPCC for the winter of 2008-09 are discussed in detail in the specific report sections. The following Summary of Findings addresses the significant points of the report discussion. These findings are based on projections of electric demand requirements, available resources and transmission configurations. This report evaluates NPCC’s and the associated Balancing Authority Areas’ ability to deal with the differing resource and transmission configurations within NPCC and the associated Balancing Authority Areas’ preparations to deal with the possible uncertainties identified in this report.

Summary of Findings

- The forecasted coincident peak demand for NPCC during the peak week (week beginning January 11, 2009)\(^2\) is 114,010 MW. The capacity outlook indicates a forecasted Net Margin for that week of 17,670 MW. This equates to a net margin of 15.5 % in terms of the 114,010 MW forecasted peak demand.

- The minimum forecasted Net Margin of 15.1% occurs during the week beginning February 1, 2009. During this week, the Net Margin available to NPCC is forecasted to be 16,865 MW.

- The largest forecasted Net Margin of 38.9% occurs during the week beginning March 29, 2009. During this week, the Net Margin available to NPCC is forecasted to be 35,940 MW.

- The forecasted net margins for the 2008-09 Winter Operating Period are similar to the previous winter.

- During the NPCC forecasted peak week, the forecasted net margin in terms of forecasted demand ranges from approximately 4.2% in Québec to 41.2% in New York.

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\(^1\) The NPCC Assessments can be downloaded from the NPCC members’ website http://www.npcc.org/documents/reports/Seasonal.aspx.

\(^2\) Load and Capacity Forecast Summaries for NPCC, IESO, ISO-NE, NYISO, HQ and the Maritimes are included in Appendix I.
• There is approximately 2,728 MW of forecasted new installed capacity for this operating period (178 MW in the Maritimes, 150 MW in New England, 318 MW in New York, 1,680 MW in Ontario and 402 MW in Québec). No delays are forecasted for the commissioning of these resources. However, any delay should not materially impact the overall net margin projections for NPCC.

• The Maritimes is projecting adequate net margins for the Winter Operating Period. These net margins range from 323 MW to 811 MW (6% to 16%). The corresponding 2007-08 winter Maritimes net margin range was 10% to 29%. The difference in the net margin range is due to the Point Lepreau Nuclear station (approximately 600 MW) refurbishment, scheduled to be completed in July 2009. If load is higher than normal or if resource outages are higher than projected, net margin for some weeks may become negative. That should not be a problem as the Feasible Transfer Capability from Québec and New England to the Maritimes area totals 1,500.

• In recent winters, New England has taken steps to ensure sufficient gas-fired generation availability during the winter period. New England has also taken steps to increase dual-fuel generation and now has 5,100 MW of primary-fueled, gas-fired generators that also have secondary-fuel capability, which primarily burn light-end liquids. In addition, to ensure system reliability, ISO-NE continually works to enhance the operational coordination between electric system operators and regional gas control.

• In New England the remaining components of the Middletown-Norwalk phase of the Southwest Connecticut Reliability Project are expected to be completed by the first quarter of 2009. The 45-miles of 345-kV overhead line portion of the project between Middletown, CT and East Devon substation (Milford, CT) have already been completed. Two 345 kV underground cables between East Devon-Singer (Bridgeport, CT) and Singer-Norwalk substations with a 345/115-kV autotransformer at Singer and a second at Norwalk Substation are scheduled to be in-service by the first quarter of 2009.

• Hydro One has begun work at Hawthorne TS in Ottawa to expand the 230 kV yard in preparation for the new 1,250 MW, 230 kV double circuit connections to Hydro-Québec. TransÉnergie is commissioning the new Outaouais 315/230 kV substation to integrate the interconnection with Ontario expected to be in-service Q2 2009.

• Since the summer of 2008, 318 MW of additional resources have been added to the New York system. Two capacitor banks are scheduled to be added to Millwood 345 kV station in the first quarter of 2009 for added voltage support in the lower Hudson Valley.

• In Ontario, Claireville Station is undergoing a major reconfiguration of the station and the replacement of existing older SF6 switchgear that will continue into early 2009.
• 11 miles of fluid-filled 138 kV submarine cables between Norwalk, CT and Northport, NY have been replaced with three new solid-core cables, improving the reliability of this tie between New York and New England.

• The winter assessment indicates that each NPCC Area is reasonably prepared and is reviewing the necessary strategies and procedures to deal with operational problems and emergencies if they develop. The CO-12 Working Group believes that these preparations are valid for dealing with the various operating scenarios expected during the Winter Operating Period.

The CO-12 Working Group believes that NPCC and the associated Balancing Authority Areas have adequate generation and transmission for the Winter Operating Period. However, the resource and transmission assessments in this report are mere snapshots in time and base case studies. Continued vigilance is required to monitor changes to any of the assumptions that can alter this report’s findings. Within NPCC this is accomplished through the actions outlined in NPCC Procedure C-13, Operations Planning Coordination.
2. **Introduction**

The NPCC Task Force on Coordination of Operation (TFCO) established the CO-12 Working Group to conduct overall assessments of the reliability of the generation and transmission system in the NPCC Region for the Summer Operating Period (defined as the months of May through September) and the Winter Operating Period (defined as the months of December through March).

For the 2008-09 Winter Operating Period\(^3\) the CO-12 Working Group:

- Examined historical winter operating experiences and assessed their applicability for this period.
- Reviewed the existing emergency operating procedures as well as recent additions and revisions within NPCC.
- Reported potential sensitivities on an Area basis, which may impact resource adequacy, including temperature deviations, merchant plant delays, load forecast uncertainties, fuel availability, load response programs and transmission adequacy.
- Examined the fuel supply infrastructure on an Area basis and included a list of dual-fuel facilities.
- Examined wind generation capacity by Area and reported and listed existing wind facilities and upcoming wind capacity.
- Provided a winter 2007-08 post-seasonal assessment and a historical peak demands table by Area.

\(^3\) For the purposes of this report, the Winter Operating Period includes the week beginning November 30, 2008 to the week beginning March 29, 2009 inclusive.
3. **Demand Forecasts for Winter 2008-09**

The non-coincident forecasted peak demand for NPCC over the 2008-09 Winter Operating Period is 114,111 MW. This peak demand translates to a coincident peak demand of 114,010 MW which is expected during the week beginning January 11, 2009. Demand and Capacity forecast summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I.

Ambient weather conditions are an important variable impacting the demand forecasts. However, unlike the summer demand forecasts, the non-coincident peak demand varies only slightly from the coincident peak forecast in the winter. This is mainly due to the fact that the drivers that impact the peak demand are concentrated into a specific period in time. In winter, the peak demands are determined mainly by low temperatures along with the reduced hours of daylight that occurs over the first few weeks of January.

While the peak demands appear to be confined to a few weeks in January, each Area is aware that reduced margins could occur during any week of the operating period as a result of weather variables and / or higher than normal outage rates.

The impact of extreme ambient weather conditions on load forecasts can be demonstrated by various means. The IESO and Maritimes represent the resulting load forecast uncertainty in their respective Areas as a mathematical function of the base load. The NYISO and TransÉnergie (transmission operations division of Hydro-Québec) use a weather index that relates air temperature and wind speed to the load response and increases the load by a MW factor for each degree below the base value. ISO-NE relates air temperature to the load response and increases the load by a MW factor for each degree below the base value.

The method each Balancing Authority Area uses to determine the peak forecast demand and the associated load forecast uncertainty relating to weather variables is described in greater detail in Appendix IV. Below is a summary of all Balancing Authority Area forecasts.
Summary of Balancing Authority Area Forecasts

Maritimes

Based on the Maritime Area 2008-09 demand forecast, a peak of 5,547 MW is predicted to occur for the Winter Operating Period, December through February. The peak demand is forecasted to occur the week beginning February 8, 2009. The forecasted peak is about 2.9 % higher than last year’s actual winter peak of 5,385 MW which occurred January 22, 2008. The reduction for winter 2007-08 in demand was due to higher than forecasted temperatures, resulting in slightly lower electric heating load and shutdowns of industrial load.

It should be noted that the Maritimes Area load is simply the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes load included a coincidence factor, the forecast load would be approximately 1-3 % lower. The following graph illustrates the weekly Maritimes forecast.

New England

The New England Balancing Authority Area reference forecast (50 % chance of being exceeded) for winter 2008-09 projects a peak demand of 23,030 MW. This projected peak is 40 MW (0.2 %) lower than the 2007-08 winter projected peak of 23,070, and 435
MW (1.9 %) higher than the 2007-08 weather normal winter peak of 22,595 MW. The lower forecast this winter is due to improvements in the energy and peak forecasting methodologies which resulted in lower forecasts of winter peak levels. New England’s all-time winter peak demand of 22,818 MW occurred on January 15, 2004. If extremely cold weather occurs for a prolonged period during the upcoming Winter Operating Period, the winter peak demand could reach 24,175 MW (10 % chance of being exceeded).

The following graph illustrates the range of potential peak demands that ISO-NE may experience this winter and compares them to historical peaks (1980-2008).

**Figure 2**
New England Winter 2008-09 Weekly Load Profile

![Graph showing load profile for New England Winter 2008-09]

**New York**

The New York Balancing Authority Area peak load forecast for this Winter Operating Period is 25,293 MW. That is 31 MW lower than the 2007-08 Winter Operating Period forecast of 25,324 MW. This forecast load is 0.97 % lower than the all-time winter peak load of 25,541 MW that occurred on December 20, 2004. The daily peak demand observed by New York during the Winter Operating Period occurs in the late afternoon or early evening hours.

The following illustration provides the range of potential peak demands that New York may experience this winter.
Figure 3
New York Winter 2008-09 Weekly Load Profile

Ontario

The forecasted weather normal hourly peak demand for this Winter Operating Period is 23,708 MW. This is 415 MW lower than the 24,123 MW forecasted last winter. Though the economy is not in a recession, demand from the energy intensive industrial sectors continues to decline. Growth in the service sectors has not offset the decline in these other high-demand sectors. Going forward, the same factors are expected to persist, leading to relatively minimal growth. However, growing amounts of conservation will more than offset the underlying growth in demand and lead to an overall decline. The actual peak demand for the 2007-08 Winter Operating Period was 23,054 MW on February 11, 2008, which was the latest the winter peak has ever occurred in Ontario.

The following graph illustrates the range of possible demands that the IESO may experience over this Winter Operating Period.
Québec

Hydro-Québec’s reference peak demand forecast for the 2008-09 Winter Operating Period is 36,379 MW, predicted to occur during the week beginning January 11, 2009. This is practically the same as the 2007-08 forecast of 36,361 MW. A downward revision of the industrial sector forecast has been counterbalanced by a demand increase in other sectors. The actual peak demand for the 2007-08 Winter Operating Period was 35,352 MW on January 21, 2008 at 8h00. The all-time demand peak was 36,268 MW on January 15, 2004.

These values do not include the supply of 145 MW of load to Cornwall over the Cedar Rapids Transmission (CRT) system (154 MW with losses). This load in the Cornwall area of Ontario is tapped-off the CD11 and CD22 120-kV lines which are in a radial configuration from Les Cèdres Generating Station in Québec to Dennison in New York. The transfer from Dennison to Cornwall must be around zero, so that this load is served by Québec. For this reason, the Cornwall load is included in Table 6 of Appendix I. The demand forecast in Table 6 for the week beginning January 11 is therefore 36,533 MW.

Throughout the Winter Operating Period, as seen in Table 6 of Appendix I, weekly peak load varies from 30,232 MW for the week beginning November 30 to 36,533 MW for the week beginning January 11 and back to 26,907 MW for the week beginning March 29.

The following graph demonstrates the range of potential weekly peak demands on the Québec system for the 2008-09 Winter Operating Period.
4. **Resource Adequacy**

**NPCC Summary for Winter 2008-09**

The following assessment of resource adequacy indicates the week with the highest coincident NPCC demand is the week beginning January 11, 2009. Detailed Projected Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.

Table 1 of Appendix I is the NPCC load and capacity summary for the 2008-09 Winter Operating Period. Tables 2 to 6, contain the load and capacity summary for each NPCC Balancing Authority Area. Each entry in Table 1 is simply the aggregate of the corresponding entry for the five NPCC Balancing Authority Areas.

The NPCC Net Margins vary from 16,865 MW to 35,940 MW during this Winter Operating Period.

The following table (Table A) summarizes the load and capacity situation for the peak week beginning January 11, 2009 compared to the winter 2007-08 forecasted peak week (week beginning January 13, 2008).
## TABLE A

**Comparison of Resource Adequacy**

*2008-09 Forecast and 2007-08 Forecast*

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capacity</td>
<td>157,377</td>
<td>154,901</td>
<td>2,476</td>
</tr>
<tr>
<td>Purchases</td>
<td>80</td>
<td>25</td>
<td>55</td>
</tr>
<tr>
<td>Sales</td>
<td>0</td>
<td>182</td>
<td>-182</td>
</tr>
<tr>
<td><strong>Total Capacity</strong></td>
<td><strong>157,457</strong></td>
<td><strong>154,744</strong></td>
<td><strong>2,713</strong></td>
</tr>
<tr>
<td>Demand</td>
<td>114,010</td>
<td>114,521</td>
<td>-511</td>
</tr>
<tr>
<td>Interruptible load</td>
<td>4,109</td>
<td>3,208</td>
<td>901</td>
</tr>
<tr>
<td>Maintenance/De-rate</td>
<td>11,096</td>
<td>6,493</td>
<td>4,603</td>
</tr>
<tr>
<td>Required Reserve</td>
<td>7,130</td>
<td>7,317</td>
<td>-187</td>
</tr>
<tr>
<td>Unplanned Outages</td>
<td>11,660</td>
<td>12,476</td>
<td>-816</td>
</tr>
<tr>
<td><strong>Revised Net Margin</strong></td>
<td><strong>17,670</strong></td>
<td><strong>17,145</strong></td>
<td><strong>525</strong></td>
</tr>
</tbody>
</table>

Installed Capacity has increased from last winter by 2,476 MW to 157,377 MW.

The following are the assessments for each Balancing Authority Area supporting this overall resource adequacy assessment.
Projected Demand and Capacity Analysis by Balancing Authority Area

Maritimes

The Maritimes is expecting a net increase of 177.5 MW of installed wind generation during this Winter Operating Period. The Installed Capacity for the assessment period is between 7,172 MW and 7,252 MW. The Total Capacity available during the forecasted peak load week is 7,242 MW when firm sales and purchases are taken into account.

When allowances for known maintenance and de-ratings, required operating reserve and unplanned outages are considered, the Maritimes Area is projecting adequate net margins for the Winter Operating Period. These net margins range from 323 MW to 811 MW (6% to 16%). The corresponding 2007-08 winter Maritimes net margin range was 10% to 29%. The difference in the net margin range is due to the Point Lepreau Nuclear station (~ 600 MW) refurbishment. If load is higher than normal or if resource outages are higher than projected, net margin for some weeks may become negative. That should not be a problem as the Feasible Transfer Capability from Québec and New England to the Maritimes area totals 1,500.

The Maritimes Area assesses its seasonal resource adequacy in accordance with NPCC C-13 Operational Planning Coordination procedure. As such, the assessment considers the regional operating reserve criteria; 100% of the largest single contingency and 50% of the second largest contingency.

The Maritimes area is forecasting normal hydro conditions for the 2008-09 Winter Operating Period. The Maritimes Area hydro resources are run of the river facilities with limited reservoir storage facilities. These facilities are primarily utilized as peaking units and providing operating reserve.

The Maritimes Area is not relying on outside assistance/external resources during the Winter Operating Period.

New England

With the expected weather and normal resource outages, capacity within New England is forecasted to be sufficient to meet load plus operating reserve requirements during this Winter Operating Period. The lowest projected net margin of 3,379 MW is expected to occur during the weeks beginning January 11 and 18, 2009 while the highest projected net margin of 10,648 MW is expected to occur during the week beginning March 29, 2009, if all assumed system conditions materialize under the reference load forecast (50% chance of being exceeded).
The net margin is based on known outages, an allowance for unplanned outages\(^4\), anticipated generation additions and retirements, projected firm purchases and sales, and the impact of expected Demand Response Programs.

In addition to the allowance for unplanned outages, an allowance for higher unplanned outages due to possible natural gas shortages of New England generators is included in the seven highest load weeks of January and February. This allowance, which is assumed to be 3,900 MW under the reference load forecast, significantly decreases the forecasted net margins during the weeks of January 4\(^{th}\) through February 15\(^{th}\).

During times of capacity deficiencies, ISO New England invokes ISO-NE Operating Procedure No. 4 – *Actions during a Capacity Deficiency* (OP-4), which includes public appeals for conservation, purchasing emergency energy from the neighboring Areas, interrupting real time demand response providers, and implementing voltage reductions.

While ISO New England expects to have adequate margins for this winter under expected weather and normal resource outages, if operable capacity shortages occur due to higher than expected resource unavailability or higher than expected load conditions, ISO New England may have to implement ISO-NE OP 4 or ISO-NE Operating Procedure No. 21 – *Action during an Energy Emergency* (OP 21). OP 21 is an emergency operating procedure designed to provide additional commitment and dispatch flexibility to manage and conserve fuel-limited supply-side resources.

**New York**

The NYISO forecasts available installed capacity of 37,445 MW for the peak week demand forecast of 25,293 MW. Available installed capacity is the total installed capacity less known planned and predicted forced outages. Accounting for purchases, sales, required operating reserve, planned and unplanned outages results in a Net Margin of 10,432 MW.

These resources represent all generation capability located physically within the New York Balancing Authority Area that is able to participate in the NYISO ICAP market. In addition to these generation resources within the New York Balancing Authority Area, generation resources external to the New York Balancing Authority Area can also participate in the NYISO ICAP market. Resources within the New York Balancing Authority Area that provide firm capacity to an entity external to the New York Balancing Authority Area are not qualified to participate in the ICAP market.

NYISO conducts semi-annual and monthly Installed Capacity (ICAP) auctions. Based on the forecast load for 2008, the ICAP requirement is 38,880 MW based on a 15% installed reserve margin (IRM) requirement. Last year the IRM requirement was 16.5%. On

\(^4\) The allowance for unplanned outages is based on historical trends and is estimated to be between 2,200 MW and 3,200 MW during the winter.
February 29, 2008, the Federal Electric Regulatory Commission issued an order accepting the New York State Reliability Council's (NYSRC) filing of a 15% IRM for the State of New York. In addition to the generation resources within the New York Area, generation resources external to the New York Area can also participate in the NYISO ICAP market. An external ICAP supplier must declare that the amount of generation that is accepted as ICAP in NY will not be sold elsewhere. The external Area in which the supplier is located has to agree that the supplier will not be recalled or curtailed to support its own loads; or will treat the supplier using the same pro rata curtailment priority for resources within its Balancing Authority Area. The energy that has been accepted as ICAP in NY must be demonstrated to be deliverable to the NY border. The NYISO sets a limit on the amount of ICAP that can be provided by suppliers external to NY. Resources within the New York Balancing Authority Area that provide firm capacity to an entity external to the Area are not qualified to participate in the NYISO ICAP market. When allowances are taken for unplanned outages (based on historical performance of 4.46% unavailable capacity), the net available resources will be 35,149 MW, which will be sufficient to meet the New York Balancing Authority Area load and operating reserve requirement during the peak load hours, with an additional reserve margin of approximately 8,056 MW expected at peak conditions.

Since the summer of 2008, 318 MW of additional resources have been added to the New York system. The Châteauguay, Altona, and Canandaigua wind projects are 106.5 MW, 99 MW, and 82.5 MW wind farms, respectively. The Gilboa 1 up-rate is 30 MW.

NYISO expects approximately 356 MW of load relief from emergency operating procedures that include internal load curtailment by the transmission owners, public appeals and 5% system wide voltage reductions. Participation in the Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) programs represents an additional 1,735 MW available through the market. EDRP participants voluntarily curtail load when requested by the NYISO. SCR participants must, as part of their agreement, curtail power usage, usually by shutting down when asked by the NYISO. Neither EDRP nor SCR are considered interruptible load in the Load & Capacity Table calculations of net margin. (Appendix I)

Ontario

Ontario is expecting a net increase of 1,680 MW of new generation resources during the winter operating period. This increase is due to 1,195 MW of new gas fired generation, 53 MW of new hydro-electric generation and 432 MW of new wind generation. With the addition of the new generation, Ontario is expected to have a net margin of 6.5% during the peak week. Based on the forecast weather normal demands, the IESO is projecting a minimum net margin of about 3.5% during the week beginning February 8, 2009, if all generator unit planned outages were allowed to proceed as requested. This analysis is based on a review of known outages, a projection of unknown outages, and a forecast of price responsive loads.
For this report period, known outages include those resources that are scheduled to be on planned outages, transmission constrained resources as well as the difference between the installed capacity and the dependable capacity associated with certain resources.

Unknown outages represent an estimate of the forced outages that may be experienced in this study period.

The net margin shown in table 5 of Appendix I, does not consider all the additional off-market control actions available to the IESO. For example, the IESO can institute a 3 % or a 5 % voltage reduction. These control actions have the effect of reducing the demand by 1.5 % to 2.6 %, which, equates to approximately 356 MW to 616 MW on the peak week for weather normal demands.

Additionally, the IESO can trigger an Emergency Load Reduction Program (ELRP) which has 358.5 MW of load registered. This program is activated as part of the IESO's Emergency Operating Control Actions.

The risks associated with this analysis are that demands may be heavier than expected due to extreme weather, generators on outage may not return to service as scheduled or generators forced unavailable may be higher than projected. The projected margins and control actions available to the IESO are continuously assessed. Should the IESO determine that the Ontario Area is deficient; the appropriate course of action will be taken. Actions can include the adjustment of outage programs, securing of assistance via market mechanisms or as a final step, the acquisition of emergency energy from other Areas.

Québec

During the 2008-09 Winter Operating Period, the Québec Balancing Authority Area will have 42,211 MW of installed generation capacity.

Capacity adjustments totaling 240 MW have been made on the system since the 2007-08 Winter Operating Period.

| Capacity adjustments on existing G. Stations | 35 MW |
| Cadillac G.S. retired (Jet fuel) | -162 MW |
| Finishing Péribonka G.S. (Hydro) | 295 MW |
| Rapides-des-Coeurs G.S. (New hydro) | 41 MW (partial) |
| Chute-Allard G.S. (New hydro) | 31 MW (partial) |

At peak load, 2,333 MW of known maintenance, constraints and hydraulic restrictions is expected, including 471 MW of wind generation derating. This brings the operable capacity to 39,878 MW in January. In addition to this, 200 MW of firm capacity purchases from New-Brunswick (Millbank) and firm sales of 543 MW (including losses) to New England (343 MW) and New Brunswick (200 MW) expected throughout the
Operating Period bring the Total Capacity to around 41,868 MW. This is slightly higher (+27 MW) than the Total Capacity projected for the 2007-08 Winter Operating Period.

The Known Maintenance and Constraints are around 2,300 to 2,500 MW during January and February. As mentioned in the NPCC Reliability Assessment for Summer 2008 in the Projected Demand and Capacity Analysis section Hydro-Québec Distribution and TransCanada Energy have negotiated a temporary shutdown of the TCE G.S. Therefore, 547 MW are included in the Known Maintenance and Constraints item in Table 6.

The winter peak is expected to materialize during the week of January 11, 2009. The forecast internal peak demand is 36,379 MW. In Table 6 of Appendix I, 154 MW is added to this amount for the Cornwall load, which is fed by radial generation from Québec. The total peak load in Table 6 is therefore 36,533 MW. Firm sales to neighboring systems, excluding the firm sale to Cornwall, amount to 543 MW. When the required operating reserve, the interruptible load and the allowance for unplanned outages and load uncertainty are taken into account, the Net Margin at peak load is 1,552 MW. This is similar to last year’s net margin at peak. During the 2008-09 Winter Operating Period, net margins varying from 1,552 MW to 11,137 MW, can be observed for Québec.

**Delays to In-service of New Generation Resources**

**Maritimes**

In the Maritimes Area 177.5 MW of wind power generation is scheduled for addition during the Winter Operating Period. A delay in putting this capacity in service will not impact reliability in the Maritimes.

**New England**

Four projects involving new generation and up-rates to existing generation, totaling approximately 150 MW, are expected to go on line in New England prior to the Winter Operating Period. If this capacity is not operational in time for the peak demand period, it will not have a significant effect on Net Margins.

**New York**

Resource additions, totaling 318 MW are expected to be available for service during the winter period. Three upstate wind farms total 288 MW. An uprate of an existing pumped-storage unit adds 30 MW.
**Ontario**

Delays to the expected new generation will not seriously harm Ontario’s capacity outlook for the winter of 2008-09. At this time, no delays are expected.

**Québec**

The Péribonka G.S. is already in service. The Rapides-des-Coeurs and Chute-Allard generating stations are now in the commissioning phase. No delays are expected.

**Fuel Infrastructure by Balancing Authority Area**

The following is a self-assessment by each Balancing Authority Area of the expected fuel supply infrastructure.

**Maritimes**

The Maritimes Area does not consider potential fuel-supply interruptions in the regional assessment. The fuel supply in the Maritimes Area is very diverse and includes natural gas, coal, oil (both light and residual), hydro, tidal, municipal waste, and wood. Fuel supplies are expected to be adequate during the projected winter period. Extreme weather conditions should have no impact on the fuel supply to the Maritimes Area. Responsibility for fuel switching plans lies with the generation owner. All applicable units have the required procedures. The only units with fuel-switching capability are at Tuft’s Cove, Nova Scotia (natural gas or oil) and Coleson Cove unit #3, New Brunswick (oil or oil/petcoke) and totaling 645 MW. Each facility maintains an adequate supply of its primary fuel.

**New England**

The majority of generators in New England are fueled by natural gas, followed by oil, nuclear, coal, hydro and renewable resources. In 2007, gas-fired generation produced over 40% of the Area’s electric energy production. New England’s heavy reliance on natural gas to generate electricity has led to winter reliability concerns, primarily due to the direct competition with the core gas markets for both supply and transportation. During the 2008-09 winter operating period, it is estimated that under the reference load forecast, approximately 4,000 MW of the total 8,900 MW of gas-only generation in New England may be temporarily unavailable to serve peak load due to the subordinate pipeline contracts held by those power generators. This analysis is based on the results of how temperature effects impact the prioritization of transportation entitlements of regional natural gas pipelines.
New England has approximately 7,600 MW of fully functional dual-fuel capacity. The Area has 5,100 MW of primary-fueled, gas-fired generators that also have secondary-fuel capability, which primarily burn light-end liquids. The Area also has another 2,500 MW of primary-fueled, heavy-oil-fired generators that have secondary-fuel capability, which primarily burn low pressure natural gas. Within New England, the total amount of generation that can burn natural gas as either a primary, secondary, startup or stabilization fuel approaches 50% of the installed capacity of the overall generation fleet.

To ensure system reliability, ISO-NE is continually working to enhance the operational coordination between electric system operators and regional gas control. ISO-NE representatives routinely meet with their counterparts within the regional natural gas industry to discuss common issues related to seasonal preparedness, emergency communications, and outage coordination. In addition, several gas sector infrastructure improvements have been recently made which increase accessibility to regional gas supplies.

ISO-NE has developed a “Cold Weather” Operating Procedure that can be implemented during extremely cold weather, when the demand for natural gas from both sectors peaks coincidentally, to help optimize the procurement of natural gas by regional power generators. This, in turn, works to improve unit availability, bolstering system reliability.

**New York**

Traditionally, New York generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements now available use natural gas as the primary fuel. While some existing generators in southeastern New York have “dual-fuel” capability, use of residual or distillate oil as an alternate may be limited by environmental regulations. Adequate supplies of all fuel types are expected to be available for the winter period.

**Ontario**

The majority of generation facilities operating on the IESO-controlled grid are represented by three basic types of fuel (Hydroelectric, Nuclear and Fossil). The fossil-fueled facilities are predominately fired by coal with an increasing portion being fired by natural gas whereas the portion of oil fired has remained relatively unchanged. Lennox GS has 4 x 500 MW generator units that can be fueled by oil or gas.

Fuel for a portion of the coal-fired resources is delivered by boat. During the winter months, shipping capability is limited by ice and weather conditions on the Great Lakes. While these conditions may prevent delivery for extended periods, all sites relying on this delivery mechanism stockpile the fuel.
As in other Areas, natural gas supplies for electricity generation in Ontario also compete with space heating requirements. Natural gas supplies and delivery infrastructures are expected to be adequate for the Winter Operating Period. The IESO and the gas distribution companies in Ontario have an established protocol whereby the gas distribution companies inform the IESO of situations that could affect gas supplies into Ontario.

At the time of this report, the IESO has not been made aware of any fuel supply concerns. It is therefore expected that adequate supplies of all fuels will be available for the Winter Operating Period.

Québec

Québec's electrical energy is largely produced by hydro generating stations located on geographically dispersed river systems. The major systems have multi-year storage capability. For planning purposes and day-to-day operation the Québec system can rely on these multi-year water reserves and on some other non-hydroelectric resources, allowing the Québec Balancing Authority Area to cope with periods of low inflows (lower than annual average). For the Winter Operating Period these non hydraulic resources consist of 714 MW of jet turbines fuelled by oil or kerosene, 675 MW of nuclear production (One generating station), 547 MW of natural gas fired generation (TransCanada Energy) and 600 MW of oil fired production (Total of 2,536 MW). This accounts for about 6 % of the installed capacity resources. The jet turbines and oil fired production are used for peaking purposes; fuel supply is not an issue in this case. Coal is not used for power generation in Québec.

In TransCanada Energy’s case, the electrical energy is supplied to Hydro-Québec Distribution under a long term firm contract. However, Hydro-Québec Distribution and TransCanada Energy have agreed to temporarily shut down the TCE generating station for 2008 and 2009. We have included the TCE capacity in the Installed Capacity column of Table 6 and an equivalent capacity in the Known Maintenance and Constraints column in the same table.

Wind Capacity Analysis by Balancing Authority Area

As seen in the wind generation analyses below, relatively little wind generation is actually on the system this year. Balancing Authority Areas have different ways of accounting for this generation. Little is known about real life operation of wind generation in terms of capacity forecasting and utilization factor. More and more of this type of generation is expected to come on line in the next few years and NPCC will unify reporting methods.
The following table illustrates the nameplate wind capacity in NPCC for the Winter Operating Period. Some Balancing Authority Areas include the entire nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Constraints section to account for the fact that some of the capacity will not be online at the time of peak. Others simply reduce the nameplate capacity by a factor and include this reduced capacity directly in the Installed Capacity section of the Load and Capacity Table.

**TABLE B**

Wind Resources by Balancing Authority Area

<table>
<thead>
<tr>
<th>Balancing Authority Area</th>
<th>Nameplate Capacity (MW) 2008-09</th>
<th>Capacity After Applied Derate Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes</td>
<td>348.3</td>
<td>194.5</td>
</tr>
<tr>
<td>New England</td>
<td>12.3</td>
<td>4.5</td>
</tr>
<tr>
<td>New York</td>
<td>994</td>
<td>298.2</td>
</tr>
<tr>
<td>Ontario</td>
<td>512</td>
<td>51.2</td>
</tr>
<tr>
<td>Québec</td>
<td>470.8</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,337.4</strong></td>
<td><strong>548.4</strong></td>
</tr>
</tbody>
</table>

**Maritimes**

The Maritimes Area currently has 170.76 MW of installed wind capacity. An additional 177.5 MW of new wind capacity is scheduled to come on-line during the winter operating period. There is 96 MW in New Brunswick, 80 MW in P.E.I. and 1.5 MW in Nova Scotia. After applying derates, the current installed wind capacity is 61.82 MW. With the expected additional on line will be 132.67 MW.

The current list of Maritimes wind generators is shown below with their de-rate value.

<table>
<thead>
<tr>
<th>Name</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New Brunswick</strong></td>
<td>None</td>
</tr>
<tr>
<td><strong>Prince Edward Island</strong></td>
<td></td>
</tr>
<tr>
<td>East Point</td>
<td>12.0</td>
</tr>
<tr>
<td>North Cape</td>
<td>2.11</td>
</tr>
<tr>
<td>North Cape</td>
<td>2.11</td>
</tr>
</tbody>
</table>
West Cape Norway Norway 8.0 3.6 1.2 29.02

**Nova Scotia**

- Nova Scotia Power Inc. 0.3
- Atlantic Wind Power 11.3
- Cape Breton Power 5.3
- Confederation 1.5
- Renewable Energy Services Ltd. 1.0
- Shearwind North 0.4 19.8

**NMISA**

- Mars Hill 13.0

**New England**

The total nameplate capability of wind generators in New England amounts to 12.3 MW. Approximately 37% of that amount, or 4.5 MW, is counted as installed capacity.

Two new wind projects amounting to 56 MW are expected to be in service by the Winter Operating Period.

**New York**

New York currently has 706 MW of wind capacity. Chateauguay, Altona, and Canandaigua wind farms are expected to be in service this summer adding a total nameplate rating of 288 MW. New York applies a 70% derate factor for wind generation in the winter operating period resulting in 298.2 MW counted towards capacity.

**Ontario**

The IESO presently has 512 MW of wind capacity.

<table>
<thead>
<tr>
<th>Wind Farm</th>
<th>Capacity (MW)</th>
<th>Mid Term (10%) MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amaranth</td>
<td>99</td>
<td>9.9</td>
</tr>
<tr>
<td>Kingsbridge</td>
<td>40</td>
<td>4.0</td>
</tr>
</tbody>
</table>
Wind capacity is forecasted using only 10% of nameplate rating for the mid term, capacity forecasts. The geographic diversity of Ontario wind resources mitigate some of the risk associated with wind speed variability. These figures do not include 432 MW of forecasted new wind generation expected on-line by the end of this Winter Operating Period.

Québec

All of the wind capacity in Québec is generated by Independent Power Producers. The capacity now in service is 471 MW. This is entirely situated in the Matapédia region of the system — around the Gaspésie peninsula near the Gulf of St-Lawrence. The capacity now under contract with HQP is 150.8 MW. Le Nordais Cap-Chat and Le Nordais Matane are now merged into one contract of 40.5 MW.

Present wind farms are:

<table>
<thead>
<tr>
<th>Name</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Le Nordais</td>
<td>40.5</td>
</tr>
<tr>
<td>Mont-Copper</td>
<td>54</td>
</tr>
<tr>
<td>Mont-Miller</td>
<td>54</td>
</tr>
<tr>
<td>Parc du Renard</td>
<td>2.3</td>
</tr>
<tr>
<td>Baie-des-Sables</td>
<td>110</td>
</tr>
<tr>
<td>Anse-à-Valleau</td>
<td>100</td>
</tr>
<tr>
<td>Carleton</td>
<td>110</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>470.8</strong></td>
</tr>
</tbody>
</table>

In 2005, HQD held a call for tenders for 1,000 MW of wind power in the Matapédia region. To date, 320 MW have been commissioned under this contract (Baie-des-Sables, Anse-à-Valleau and Carleton). The rest will be commissioned gradually until 2012. A new call for tenders by HQD for about 2,000 MW of wind generation has ended in September 2007. Winning tenders were disclosed during summer 2008. Contracts
have been approved recently by the Régie de l’énergie (Québec Energy Board). This capacity is scheduled to be commissioned between 2011 and 2015.

For the 2008-09 Winter Operating Period the entire wind generation capacity is derated. This derating is included in the Known maintenance/constraints column in Table 6 of Appendix I.
5. Transmission Adequacy

No specific NPCC Regional Transmission study has been performed for the 2008-09 Winter Operating Period in NPCC but each Area reviews its transfer capabilities on a continuous basis. Recognizing this, the CO-12 working group reviewed the Normal Transfer Capabilities (NTC) and the Feasible Transfer Capabilities (FTC) between the Balancing Authority Areas of NPCC under peak demand configurations.

The following is a transmission adequacy assessment from the perspective of the ability to support energy transfers for the differing levels, Inter-Region, Inter-Area and Intra-Area.

Inter-Regional Transmission Adequacy

Phase angle regulators (PARs) are installed on three of the four Michigan - Ontario interconnections. One PAR, on the Keith-Waterman 230 kV circuit J5D has been in service and regulating since 1975. The other two available PARs, on the Lambton-St. Clair circuits L51D and L4D, were placed in service on April 14, 2008, however, the PARs have been bypassed pending completion of agreements between the IESO, the Midwest ISO, Hydro One and International Transmission Company. The expected in service date is not known at the time of this report. The operation of the phase angle regulators will assist in the management of circulating flows. The fourth PAR, on 230 kV circuit B3N (Scott-Bunce Creek), is not expected to be available for service during the Winter Operating Period 2008-09. This PAR is located in Michigan at the Bunce Creek terminal of B3N.

Inter-Area Transmission Adequacy

The tables in Appendix III provide a summary of the normal transfer capabilities (NTC) on the interfaces between NPCC Balancing Authority Areas and for some specific load zone areas. They also indicate the corresponding feasible transfer capabilities (FTC) under peak conditions based on internal limitations or other factors and indicate the rationale behind reductions from the normal transfer capability.

The Québec to Maritimes NTC is down slightly from 1,200 MW to 1,100 MW. The Québec to New York transfer capability may reach 2,000 MW on an hour-ahead basis and depending on operating conditions in New York and in Québec. Ontario to New York NTC and FTC are up from 1,600 MW to 1,720 MW since the BP76 line is out-of-service this winter period.
**Intra-Area Transmission Adequacy Assessment**

**Maritimes**

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Winter Operating Period. The HQ – NB TTC has been lowered from 1200 MW to 1100 MW. This decrease is due to lower demand in northern New Brunswick. Part of the TTC calculation with HQ is based on the ability to transfer radial loads onto the HQ system. It should be noted that the NB – HQ TTC did not change.

**New England**

The 2008 Regional System Plan (RSP08) outlines a number of the ongoing transmission planning studies and projects that are taking place. The report continues to describe the various areas of the region where transmission projects are needed for reliability. ISO-NE continually monitors transmission facility additions and coordinates outages in order to mitigate any possible reliability risks that may be associated with changes in the transmission system.

Several new projects have been completed since the winter 2007-08 period. They include the following:

- A new 345/115 kV autotransformer at Scobie (NH) and a new Scobie-Hudson 115 kV line. These projects mitigate conditions that result in thermal overloads on the other Scobie autotransformers, and help to eliminate voltage and thermal violations in the area.
- Two new phase angle regulators, four synchronous condensers, and two auto transformers at Granite (Northwest Vermont Reliability Project).
- Brook Street - Auburn Street 115 kV line, which is part of short-term improvements currently underway to address transmission system deficiencies in Lower Southeast Massachusetts.
- Several new, short 345 kV overhead line additions and new Beseck 345 kV switching station (Southwest Connecticut Reliability Project).
- 11 miles of fluid-filled 138 kV submarine cables between Norwalk, CT and Northport, NY replaced with three new solid-core cables, improving the reliability of this tie between New York and New England.

New projects expected to be in service by the end of 2008 include:
• A Phase Angle Regulator at Saco Valley, and new substation in Fitzwilliam (New Hampshire). This helps to address existing midterm voltage and thermal performance concerns in the western New Hampshire area.

• The remaining components of the Northwest Vermont (NWVT) Reliability Project: New Haven-Vergennes-Queen City 115 kV circuit and four synchronous condensers. The NWVT Reliability Project is designed to address concerns in the broad northwestern portion of Vermont in the near- and midterm.

• In New England the remaining components of the Middletown-Norwalk phase of the Southwest Connecticut Reliability Project are expected to be completed by the first quarter of 2009. The 45-miles of 345-kV overhead line portion of the project between Middletown, CT and East Devon substation (Milford, CT) have already been completed. Two 345-kV underground cables between East Devon-Singer (Bridgeport, CT) and Singer-Norwalk substations with a 345/115-kV autotransformer at Singer and a second at Norwalk Substation are scheduled to be in-service during the first quarter of 2009.

• Two 9-mile 115-kV underground circuits between the Norwalk and Glenbrook substations in Southwest Connecticut. These are expected to provide much-needed long-term reinforcement for the Stamford area.

**New York**

Upgrades in the Rochester vicinity are completed in preparation of the Russell Station retirement last spring. Also completed for this winter was the re-conductor of the Northport – Norwalk Harbor 138 kV cable. The new cable has three circuits and operates at the same ratings as the current cable. Two capacitor banks are scheduled to be added to Millwood 345 kV station in the first quarter of 2009 for added voltage support in the lower Hudson Valley.

**Ontario**

The major transmission projects in Ontario scheduled in-service during the 2008-09 winter period are taking place at two stations. Work has started at Hawthorne TS in Ottawa to expand the 230 kV yard in preparation for the new 1250 MW, 230 kV double circuit connections to Hydro-Québec. The circuits are expected in service Q2 of 2009. Claireville TS 500/230 KV station is undergoing extensive upgrades and 230 KV breaker replacements due to the old breakers reaching their end-of-life. This project will continue well into Q2 2009.
The 230 kV breakers continue to be replaced at Lambton TS as well as Scott TS due to short circuit limitations at each of these stations. The breakers are expected to be replaced at both stations by Q2 of 2009.

Supply to the western Greater Toronto Area will be enhanced by transformer upgrades at Burlington Transformer Station with completion scheduled for the end of Q4 2008.

The situation with the Queenston Flow West project has not changed. The completion date for transmission reinforcement between the Niagara and Hamilton Burlington areas continue to be delayed. The limitations affect both the use of available Ontario generation and imports into the province. Once in service, the reinforcement project will increase the capability of the transmission system connecting the Niagara River generation at Queenston to the grid in the Hamilton area by about 800 MW. This enhancement will permit increased imports from New York of at least 350 MW up to 800 MW depending on the load and generation dispatch in Ontario.

Québec

The transmission projects to integrate Péribonka, Chute-Allard and Rapides-des-Coeurs Hydro Generating Stations as well as the Carleton wind project to the system have been completed.

In the second quarter of 2009 TransÉnergie will be commissioning a new 2 X 625 MW back-to-back HVDC interconnection with the IESO in the Ottawa-Gatineau area across the Ottawa River. In preparation for this interconnection TransÉnergie is commissioning for the 2008-09 peak period a new substation named “Outaouais”. This year, the AC sections of the station will be put in-service. This station will be integrated into the existing 315-kv double-circuit line from Chénier in the Montréal area to Vignan in the Gatineau area. The Ontario side of the station is a 230-kv section fed by a double-circuit 230-kv line from Hawthorne substation in Ottawa. No transfer capacity is available through this interconnection for the 2008-09 Winter Operating Period.

One new high voltage capacitor bank will be commissioned for the 2008-09 peak period: a 345 MVAR, 315-kv bank at Chénier.

Last year TransÉnergie was to commission the Lévis de-icing device. This has been postponed to this year because of commissioning problems. Part of this device will serve as a Static Var Compensator (-115 to +250 MVAR) to be used under normal system operation. The other part of the device will be used as a direct current generator (7,200 A at 25 kV) to eventually de-ice a specific number of 735 and 315-kv lines around the Lévis substation near Québec City. The Static Var Compensator will be available in time for the 2008-09 Winter Operating Period.
No transmission line outages are expected and no major maintenance is scheduled during the 2008-09 Winter Operating Period that will significantly affect system operations. Some notes on expected outages include:

- Synchronous Condenser CS23 at Duvernay substation in the Montréal area is out of service until June 2009. This is due to a major transformer fault. The transformer must be replaced.

- One phase of transformer T8 at Micoua 735/315 kV substation failed on September 12, 2008 and must be replaced. This transformer station is situated in the Manicouagan sub-system and integrates generation from the Manicouagan, Toulnustouc and Outardes river systems (approximately 5,000 MW). Transformer T8 (570 MVA) is therefore out of service for the Winter Operating Period.

The Duvernay Synchronous Condenser outage, mentioned above, causes 100 to 400 MW of restrictions on three 735 kV interfaces on the system. The normal transfer capability on these interfaces is usually well over 10,000 MW so that this is not expected to significantly impact transmission reliability for the 2008-09 Winter Operating Period.

Limits imposed by the forced outage during the winter of the Micoua 735/315 kV transformer T8 may reduce by 100 to 200 MW the deliverable generating capacity of that substation. The situation is presently being assessed by TransÉnergie, but it is not expected to significantly impact reliability for the Winter Operating Period.

Transmission capability for the peak period is adequate to carry the net internal demand plus the firm capacity sales and operating reserve. Moreover, enough transmission capability remains on the system to carry additional resources that would be called upon if load was greater than the forecast.

Voltage support in the southern part of the system (load area) is a concern during the Winter Operating Period especially during episodes of heavy load. TransÉnergie has an agreement with Hydro-Québec Production (the largest producer on the system) that maintenance on generators will be finished by December 1, and that all possible generation will be available. This, along with yearly testing of reactive capability of the generators, ensures maximum availability of both active and reactive power. The end of TransÉnergie maintenance on the high voltage transmission system is also targeted for December 1. Also, TransÉnergie has a target for the availability of both high voltage and low voltage capacitor banks. No more than 200 MVAR of high voltage banks should be unavailable during the Winter Operating Period. The target for the low voltage banks is 90 % availability.
6. Operational Readiness for 2008-09

Demand Response Programs

Each Balancing Authority Area utilizes various methods of demand management. In those Balancing Authority Areas where market based structures have been implemented or are evolving, there has been a shift in the contractual obligations of the interruptible loads. The move is an attempt to manage load interruption, as a result of demand exceeding resources, by giving industrial and commercial customers the ability to respond to price signals in the wholesale electricity marketplace. Many of these programs are in varying degrees of development. The following is a summary of each Balancing Authority Area’s current demand response programs available or in development to be available for the Winter Operating Period.

Maritimes

Interruptible and dispatchable loads are forecast on a weekly basis as indicated in Appendix I, Table 2 and are available for use when corrective action is required within the Area.

New England

During times of capacity deficiencies, ISO New England declares ISO New England Operating Procedure No. 4 (OP 4) – Actions during a Capacity Deficiency. That includes: public appeals for conservation, purchasing emergency energy from the neighboring Balancing Authority Areas, activating demand response resources, and implementing voltage reductions.

Demand response resources are activated through ISO New England’s Demand Response Programs. Participants within the Real-Time Demand Response Program will be involved in one of two sub-programs based on their response time (30 minutes or 2 hours). Each subprogram will require the participant to interrupt during pre-specified actions of OP 4. In addition, Participants in the Real-Time Profiled Response Program will be required to respond during certain actions of OP 4.

In the Load and Capacity Table for New England (Table 3, Appendix I), 1,856 MW of demand response resources are assumed available during OP 4 conditions for the 2008-09 Winter Operating Period. Demand response resources for this winter are approximately 600 MW greater than last winter.

In addition to the reliability-based programs, ISO-NE also administers a Real-Time Price Response program and offers the Day-Ahead Demand Response Program. Due to their voluntary nature, these programs are not included as capacity within the 2008-09 Winter Operating Period in the New England Load and Capacity Table.
New York

The NYISO Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) load relief programs are only active during the Summer Operating Period.

Ontario

Dispatchable loads are load facilities that are willing to be treated as a resource that would be dispatched off the system by the IESO once the price of energy in the real time market has exceeded the bid (to Buy) price submitted by the load. The subject load must then reduce its demand according to the dispatch instructions or the load will face compliance proceedings. Based on this year’s indication, the values have increased from last year’s winter assessment from 494 MW to 601 MW. Other loads — contracted by the Ontario Power Authority — can provide demand response under tight supply conditions. Since the programs vary, they are given different levels of dependability at time of peak. Therefore, 269 MW is included in Table 5, Appendix I for this Winter Operating Period.

In 2002, the IESO instituted an Emergency Demand Response Program to provide additional demand relief under emergency conditions. The program currently involves 16 different customer sites with approximately 359 MW of load contracted in this ancillary service. When requested, the customers would reduce their demand on a voluntary basis. This demand response program would be implemented just prior to the interruption of firm load. The effectiveness of the program has been reviewed by the IESO Board and approvals have been received to extend the program.

Québec

Various demand response programs have been implemented in the Québec Area.

There are two interruptible load programs. One program — contracted by Hydro-Québec Production — involves large industrial customers (Steel and aluminum foundries) and the other program — contracted by Hydro-Québec Distribution — involves medium size industrial consumers (Paper mills and chemical industries), dispersed in all parts of the system.

The HQP program involves 791 MW of large industrial loads. The HQD program totals about 800 MW. There are operating constraints on some of these loads and Table 6 of Appendix 1 takes this into account through a “diversity factor”. The total interruptible load posted is 1,300 MW. Clients must be notified 3 or 18 hours in advance, depending on the nature of the contracts.
Hydro-Québec Distribution and TransÉnergie have developed a voltage reduction program at a large number of distribution substations. Regular testing by TransÉnergie and the addition of more transformer stations to the system has prompted Hydro-Québec Distribution to consider the voltage reduction system as a 250 MW resource. This program is included in the “Interruptible Load” column in the Appendix I, Table 6. Table 6 therefore presents 1,550 MW of load, which consists of interruptible load (1,300 MW) plus the voltage reduction program (250 MW).

A public appeal program is in place to reduce load if the reserve criterion cannot be met or if a particular event occurs on the system. This has been enforced once in 2004. At that time, the appeal was judged to provide about 800 MW of load relief.
7. Post-Seasonal Assessment and Historical Review

**Winter 2007-08 Post-Seasonal Assessment**

**NPCC**
The sections below describe briefly each Balancing Authority Area’s 2007-08 winter operational experience. Total NPCC non-coincident demand was 110,326 MW for the period.

**Maritimes**
The forecasted peak for winter 2007-08 was 5,527 MW.
Peak demand occurred on January 22, 2008 HB07:00 AST.
Demand was 5,385 MW
Control actions were not required.

**New England**
The forecasted peak for winter 2007-08 was 23,070 MW.
The actual peak load of 21,774 MW occurred January 3, 2008.
Operating Procedure 4 (OP 4) was implemented on December 1st due to a combination of higher than forecast loads, higher than expected external sales and higher than expected generator outages. Also on December 1st, OP 4 was implemented locally within Maine due to gas supply issues causing approximately 1,200 MW of generator reductions in Maine.

**New York**
The forecasted peak for winter 2007-08 was 25,324 MW.
The actual peak demand of 25,021 MW occurred on January 3, 2008 HE20:00 EST.
No particular issues to report.

**Ontario**
The forecasted peak for winter 2007-08 was 24,123 MW.
The actual peak demand of 23,054 MW occurred February 11, 2009. This was the latest the winter peak has occurred.

No particular issues.

Québec

Load and Capacity

The forecast was 36,361 MW for the 2007-08 Winter Operating Period.

Peak demand occurred on January 21, 2008 at HE8:00 EST.

Demand was 35,352 MW.

Mean temperature in Montréal on peak day was -14.6°C (5.7°F) and wind velocity was 11 km/h (6 mph). Winter 2007-08 began with near normal temperatures, January was unusually warm and February temperatures were near normal. There were no exceptionally cold periods during winter.

The forecasted sales were 330 MW but the actual sales at peak time were 2,600 MW. The difference is due mainly to a 1,141 MW sale to New England on RMCC Phase II, a 333 MW sale to New-Brunswick and a 608 MW to IESO on January 21, HE8:00 EST. The actual operating reserve was 1,700 MW at peak load: 200 MW above the reserve requirement.

State of the System

All the new equipment scheduled to be in service on the system for the 2007-08 Winter Operating Period was effectively commissioned, except the Lévis de-icing device. No synchronous condensers and Static Var Compensators were unavailable during the peak period. Four 120-kV capacitor banks totaling 396 MVAR were unavailable at peak. The target is 200 MVAR. Availability of low voltage capacitor banks was within target. No 735-kV line was unavailable. Five large sub-transmission transformers in as many transformer stations were out of service during the Operating Period. Operating procedures or other mitigating measures were enacted. Finally, Gentilly 2 nuclear generating station was down on an unplanned outage from November 2, 2007, to February 2, 2008. Capacity of the station is 675 MW.

The reactive power output of generating stations in the southern part of the system at peak load was adequate considering load and system conditions during the Winter Operating Period.

Wind generation
Approximately 270 MW of wind generation was on the system during the peak hour on January 21 on a total of 360 MW.

**Voltage control**

During the 2006-2007 Winter Operating Period, TransÉnergie had to cope with voltage variations due to stiff load rises during cold spells coupled with positive ramping at the interconnections. Thus, the Automatic Shunt Reactor Disconnecting System (MAIS) operated a number of times to disconnect a shunt reactor on the system. MAIS is designed to operate following complementary and extreme contingencies to restore 735-kV system voltages.

The implementation of new operating tool to control capacitor bank switching in the Montréal area has greatly reduced the number of times MAIS operated (actually, just one time). Thus, voltage control and system management were greatly enhanced for the 2007 Winter Operating Period.

**Interconnections**

All interconnections were available during the peak load period and no significant event occurred.
Historical Winter Demand Review (Pre-2008)

The table below summarizes historical non-coincident winter peaks for each NPCC Balancing Authority Area since 2000-01.

Table C

Historical Peak Demands by Area Occurring November to March (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Ontario</th>
<th>Maritimes</th>
<th>New England</th>
<th>New York</th>
<th>Québec</th>
<th>Total NPCC Non-Coincident Demand</th>
</tr>
</thead>
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5 Forecasted peak demand for Québec includes 145 MW in Cornwall (154 MW with losses).
8. **2008 Reliability Assessments of Adjacent Regions**

ReliabilityFirst Corporation

**Introduction**

All ReliabilityFirst Corporation (RFC) members are affiliated with either the Midwest ISO (MISO) or the PJM Interconnection (PJM) regional transmission organization (RTO) for operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission utility located in Indiana, Kentucky and Ohio is not affiliated with either RTO market; however OVEC’s Reliability Coordinator services are performed by PJM. Duquesne Light Co. has recently announced its intention to withdraw from PJM and join MISO in the first quarter of 2009. For this assessment, Duquesne Light continues to be included within the PJM RTO. Also, MISO now plans to begin operation of its Ancillary Service Market (ASM) on January 6, 2009.

ReliabilityFirst does not have officially-designated subregions; however, about one-third of the RFC load is within MISO and nearly all remaining load is within PJM, except for about 100 MW of load within the OVEC Balancing Authority area. From the perspective of the RTOs, approximately 60% of the MISO load and 85% of the PJM load is within RFC. The PJM RTO also spans into the SERC region, and the MISO RTO also spans into the MRO and SERC regions. The PJM RTO operates in total as one Balancing Authority area. MISO has recently received approval to begin operation as a single Balancing Authority area; however operation as a BA is not expected to occur until January 2009.

This assessment provides information on projected resource adequacy for the upcoming winter season across the ReliabilityFirst region. The RFC Resource Adequacy Standard BAL-502-RFC-01 requires Planned Reserve Sharing Groups (PRSGs) to identify the minimum acceptable reserves to maintain resource adequacy for their respective areas of RFC. PJM operates as the PRSG for its members. The Midwest PRSG consists of a consortium of MISO members that includes about 95% of the MISO load in the RFC regional area. Since nearly all ReliabilityFirst area demand is in either Midwest ISO or PJM, the reliability of these two RTOs will determine the reliability of the RFC region. This report assesses the resource adequacy of each RTO based on the reserve margin requirements applicable to each RTO. PJM determines the reserve margin requirement for all demand within PJM. The Midwest PRSG and MAPP determine reserve requirements for most of the demand in MISO. MISO uses a 12% default reserve requirement for demand not included in the Midwest PRSG and MAPP. The combination of reserves from the Midwest PRSG, MAPP and the default reserve

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calculation was used by RFC as the MISO reserve margin target for assessing resource adequacy.

**Demand**

The analysis of the demand data for this winter assessment focuses on three factors, Total Internal Demand (TID), Net Internal Demand (NID) and Load Management (LM).

TID represents the entire forecast electric system demand. This demand forecast is based on “50/50” or average winter weather (a 50% chance of the weather being warmer and a 50% chance of the weather being cooler).

ReliabilityFirst identifies the various programs and contracts designed to reduce system demand during the peak periods as Load Management. Individual companies may implement LM through a demand response program, a direct-controlled load program, an interruptible load contract or other contractual load reduction arrangement. Since LM is a contractual management of system demand, the reserve margin requirement for the RTO includes LM. NID is total internal demand (TID) less LM. Reserve margin requirements are based on NID.

Load Management can be addressed in different ways, reflective of its operational impact on peak demand and reserve margins. LM offers the companies that have these programs and contracts a way to mitigate adverse conditions that the individual companies may experience during the winter. The total demand reduction of each RTO is the maximum controlled demand mitigation that is expected to be available at the time of the peak system demand. For the winter of 2008-09, the ReliabilityFirst RTOs have identified the following types of LM programs:

**Direct-Controlled Load Management**

There are a number of load management programs under the direct control of the system operators that allow interruption of demand (typically residential) by controlling specific appliances or equipment at the time of the system peak. Radio controlled water heaters would be included in this category. Direct controlled load management is typically used for “peak shaving” by the system operators.
Interruptible Demand

Industrial and commercial customer demands that can be contractually interrupted at the time of the system peak, either by direct control of the system operator (remote tripping) or by the customer at the request of the system operator, are included in this category.

PJM RTO Demand Data

The estimated Net Internal Demand (NID) peak of the entire PJM RTO (including portions within an adjacent Regional Entity) for the 2008-09 winter season is 110,700 MW and is projected to occur in January. This value is based on the Total Internal Demand (TID) forecast prepared by PJM staff with the full utilization of the load management placed under PJM coordination. The forecast is dated January 2008, and is based on economic data from late 2007 for the geographic area of the PJM RTO.

Emergency Load Management placed under PJM coordination is PJM’s LM program. PJM utilizes both types of LM, Direct Control Load Management (DCLM), and Interruptible. Since the DCLM program consists primarily of air conditioning load, DCLM is zero during the winter for PJM. However, there is 4,000 MW of Interruptible Demand.

The estimated Total Internal Demand (TID) of PJM RTO for the 2008-09 winter season is 114,700 MW and is projected to occur in January. This value is based on an independent demand forecast prepared by PJM staff for each PJM zone, region and the total RTO. This compares to the 2007-08 metered peak demand of 111,724 MW. The 2008-09 forecast TID is 2,976 MW (2.7%) higher than the 2007-08 metered peak demand.

MISO Demand Data

The estimated Net Internal Demand (NID) coincident peak of the entire Midwest ISO Market Area (including portions within adjacent Regional Entities) for the 2008-09 winter season is 79,300 MW and is projected to occur in December. This value is based on the Total Internal Demand (TID) demand forecast prepared by the MISO load serving entities and the expected peak reduction from various LM programs. The MISO load serving entities developed their demand forecasts at different times since the last half
of 2007, so the economic basis for each company forecast reflects the specific economic data of that company’s planning area at the time of their forecast.

The amount of MISO market participant demand response or load management expected at the time of the peak is 3,200 MW. This is categorized as 600 MW of DCLM with an additional 2,600 MW of Interruptible Demand.

The estimated coincident Total Internal Demand (TID) of MISO for the 2008-09 winter season is 82,500 MW and is projected to occur in December. This value is based on information provided by the load serving entities. This compares to the 2007-08 winter peak demand of 83,930 MW. The 2008-09 forecast demand is 1,430 MW (1.7%) lower than the actual 2007-08 peak demand.

**RFC Demand Data**

In this assessment, the data related to the RFC areas of PJM and MISO are combined with the data from the Ohio Valley Electric Corporation (OVEC) to develop the overall RFC regional data. The RFC demand forecast also accounts for expected demand diversity among these entities. RFC uses the minimum diversity from the past 5 years which is 0.4% in January.

Approximately 85% of the PJM RTO demand and approximately 60% of the MISO market load is within the RFC region. Since OVEC is not a member of either RTO, the 104 MW of OVEC demand was added to the non-coincident demand of the PJM and MISO areas; a 0.4% diversity factor, the minimum diversity in January over the past five years of history, was applied; and the result rounded to the nearest 100 MW. The resulting coincident peak for the RFC region is 140,900 MW NID and 146,800 MW TID. The forecast NID peak is 5,500 MW (3.8%) lower than the forecast demand for 2007-08. This 2008-09 NID forecast is lower as a result of lower expected economic activity at the time the demand forecasts were prepared, and 3,600 MW of additional LM. Most of the additional 3,600 MW of LM was provided through the PJM RPM process since there are now more participants in the program. The forecast TID peak is 4,405 MW higher than the actual peak demand of 142,395 MW that occurred on January 2, 2008 for the ReliabilityFirst regional area. This difference is believed to be attributable to moderate temperatures last winter and projected lower economic activity for this winter. ReliabilityFirst does not adjust actual demand data for weather conditions. This compares to a forecast with normal winter temperatures and an increase in economic
activity for 2008-09 over 2007-08, although at a lower rate of increase than in prior forecasts.

Demand Sensitivity

Although the demand forecasts used in this assessment were collected in recent months, these forecasts were prepared months earlier. Both weather and economic conditions have significant influence on the peak demands. Any deviation from the original forecast assumptions for those parameters could cause the aggregate 2008-09 winter peak to be significantly different.

For the winter of 2008-09, a 90/10 TID forecast was prepared by PJM for its load zones as a sensitivity for extreme weather. A 90/10 demand forecast includes weather related demand for weather that has a 90% chance of being warmer and a 10% chance of being cooler. The PJM load zones that are in RFC have a non-coincident 90/10 demand of 105,800 MW, a 5.4% increase. The MISO performs a statistical analysis of the participants’ 50/50 NID forecast and historical demand data to calculate a 90/10 demand forecast. From this analysis there is a 6.0% increase in the demand of the RFC area of MISO to 49,800 MW for 90/10 weather. For the winter of 2008-09, the NID forecast based on 90/10 weather for the MISO and PJM areas, including OVEC and a 0.4% demand diversity, was used to calculate the sensitivity of the reserve margin to extreme weather in RFC. The results of this demand sensitivity are included in the Reliability Assessment Analysis section of this report.

Generation

The generating capacity in this assessment represents the rated capability of the generation in OVEC and in the PJM and MISO market areas. The category of Existing Capacity listed as “certain” represents existing resources in PJM’s Reliability Pricing Model (RPM) and Designated Network Resources (DNR) in the MISO market during the winter.

The “uncertain” resources are the existing generation that represents wind/variable resource deratings, generating capacity that has not been studied for delivery, and capacity located within the region that is not part of PJM committed capacity or MISO DNR.
“Planned” capacity additions are those additions expected to go in-service during the winter period and are included in the determination of the reserve margins. Any “proposed” capacity additions have an uncertain in-service status for this winter and are not included in the reserve margins.

The recent emphasis on renewable resources is increasing the amount of wind power capacity being added to systems in the Reliability First Region. In this assessment, the amount of available wind power capability included in the reserve calculations is less than the nameplate rating of the wind resources. PJM uses a three year average of actual wind capability during the summer daily peak periods as the expected wind capability. Generation at the time of the winter peak that is greater than the on peak wind capability is an energy only resource. Until three years of operating data is available for a specific wind project, that project is assigned 13% of the name plate rating as its on peak capability. In MISO, wind power providers may declare up to 20% of nameplate capability as DNR. The difference between the nameplate rating and the expected wind capability is accounted for in the existing “uncertain” category.

Scheduled maintenance and any existing capacity that is inoperable for this winter is not included in this assessment of reserve margins. Generally, scheduled maintenance is minimized during the peak demand periods. This inoperable capacity listed during the winter peak (January) is expected to be zero for both PJM and MISO.

**PJM Generation**

The whole PJM RTO has 161,300 MW of capacity for this winter that is identified as “certain” in this assessment. Under the Reliability Pricing Model (RPM), all capacity that has cleared in the capacity market has to be in service prior to June 1. Therefore, there is no “planned” capacity included for this winter. There is also 1,800 MW of generation related to capacity de-ratings of wind generators and generators that are energy-only participants in the PJM market. Since these resources are not in the RPM market, the deliverability and availability of this generation at the time of the peak is uncertain. Therefore, in this assessment none of this capacity is included in the PJM reserve margins.

**MISO Generation**

The whole MISO RTO has 107,100 MW of DNR capacity for this winter that is identified as “certain” in this assessment. No additional capacity is expected to go in service during
the winter. However, there are 19,200 MW of capacity in the MISO RTO that is “uncertain” capacity, consisting of uncommitted resources and the de-rated amount of wind energy capacity. None of this uncertain capacity is included in the reserve margin calculation.

**RFC Generation**

The RFC analysis includes only generation physically located within the ReliabilityFirst Region, although generating capacity outside the regional area owned by member companies may be included with the scheduled power imports.

The amount of “certain” OVEC, PJM and MISO capacity in RFC is 211,000 MW. No additional capacity is expected to go in service during the winter. All of the “certain” capacity in each RTO is determined to be fully deliverable by PJM and MISO within their respective RTOs. There is also 6,800 MW of capacity in the RFC region that is “uncertain” capacity, consisting of uncommitted resources and the de-rated amount of wind energy capacity. None of this uncertain capacity is included in the reserve margin.

Deliverability of capacity between the RTOs is not addressed in this report. However, each of the reserve requirement studies conducted has assumed limited or no transfer capability between these RTOs. Studies by the RFC Transmission Performance Subcommittee indicate there is additional inter-RTO transfer capability. The limited use of transfer capability in the reserve requirement studies provides a level of conservatism in this resource assessment.

Included in the total of “certain” generation is 226 MW of wind power expected at the peak. An additional 1438 MW of wind power is categorized as “uncertain” due to the variable nature of wind.

Also included in the total of “certain” generation is 700 MW of biomass generation expected at the peak. There are no other renewable categories being reported by the RTOs within the RFC region.
Hydro generation represents approximately 3% of the capacity within the RFC region. A Survey of Midwest ISO Market Participants determined that reservoir levels are projected to be at average levels for the winter period. Hydro conditions are also expected to be at normal levels within the PJM area. There is a low probability that water levels will create problems during winter peak conditions.

There are no expected conditions that would create capacity reductions for this winter.

Although there have been fuel delivery issues in the past within the region, there currently are no existing fuel delivery concerns. Within PJM, generation with on-site fuel supplies is required to maintain a minimum fuel level or be dispatched to conserve fuel supplies. PJM also performs sensitivity studies which include gas curtailments as part of PJM winter seasonal assessments.

**Purchases and Sales**

PJM and MISO have reported expected firm purchases and sales across their RTO boundaries at the time of the peak. This net interchange is due to member ownership interest in generation outside the RTO boundary, and contracted transactions. Specific transactions identified by PJM and MISO as interchange that supports the reserve margins in RFC are firm transactions with firm transmission reservations. Liquidated damages contracts are not included as firm transactions.

Some of the total interchange reported by PJM and MISO is due to jointly owned generation. These resources are located in one RTO, but have owners in both RTOs with entitlements to the generation. Also, some of the interchange in PJM and MISO comes from OVEC entitlements. Since the jointly owned generation and the OVEC generation is all within RFC, the jointly owned and OVEC generation is included in RFC’s generation and not in the RFC net interchange. Other transfers between the RTOs are not included in the RFC interchange when these transfers originate and terminate within the RFC region. Therefore, the total net interchange for the RFC region is not a simple summation of the PJM and MISO RTO interchange.

Since both the MISO and PJM balancing authority areas span into neighboring regions, the values shown below for each RTO are for the total of the respective RTO footprint.
The RFC net interchange below only includes that portion of the respective RTOs within the ReliabilityFirst regional area.

**PJM Net Interchange**

Firm power transfers into all of PJM are reported to be 2,700 MW. Firm power transfers out are reported to be 4,200 MW. Net interchange is a 1,500 MW power export flowing out of the PJM RTO. Any firm capacity from outside the PJM area would be used as any other market resource and, therefore, could be used for emergency and reserve sharing purposes.

**MISO Net Interchange**

MISO has reported net interchange (purchases) of 5,500 MW into the whole MISO market at the time of the peak demand. Any firm capacity from outside the MISO market area would be used as any other market resource and, therefore, could be used for emergency and reserve sharing purposes.

**RFC NET Interchange**

The PJM purchases from outside the RTO and the RFC region are 200 MW. Sales from generation within the PJM RTO to areas outside of the RFC region are 2,200 MW. The MISO reported net interchange of 5,500 MW has 2,000 MW scheduled into the RFC area of MISO with the remaining 3,500 MW scheduled into the MRO and SERC areas.

Therefore, the projected net interchange transactions for MISO and PJM that cross the RFC regional boundary at the time of the peak are 2,200 MW in and 2,200 MW out which is zero net interchange. These are only firm transactions. Other transactions may occur this winter, but they are not considered to be firm transactions and are not included in this analysis.

**Transmission**

New facility additions to the bulk-power system that have been placed in-service since last winter include a total of 39 miles of transmission line at 230 kV and above, plus nine transformers with a total capacity of about 3,500 MVA. An additional five transformers
with a total capacity of about 3,000 MVA are projected to be placed in-service by or during this winter. These system changes are expected to enhance reliability of the bulk-power system.

There have been numerous facility upgrades to the Midwest ISO members’ transmission systems since the 2007-08 winter period. These can be referenced at http://www.midwestiso.org/publish/Document/5d42c1_1165e2e15f2_-7b940a48324a?rev=1. Some of these major facility additions by this winter for the MISO area of ReliabilityFirst include:

- Install third 345/138 kV transformer bank at Pierce/Beckjord in Duke Energy Midwest
- Install second 345/138 kV transformer bank at Hillcrest in Duke Energy Midwest
- Install new substation with 345/138 kV transformer at West Medina in FirstEnergy
- Install third 345/138 kV transformer bank at Tallmadge in Michigan (ITC)
- Install second 345/138 kV transformer at Hiple in NIPSCO

The major facility additions by this winter for the PJM area of ReliabilityFirst include:

Hunterstown 230 kV ring bus and two Hunterstown 230 kV capacitors in FirstEnergy (MetEd)

New 500/230-kV substation at Orchard to tap existing Salem-East Windsor 5021 500 kV line and install 500/230-kV transformer bank at Orchard with the low side to tap into the Churchtown-Cumberland 230 kV line

- Orchard-New Freedom-East Windsor 500 kV line construction
- Convert 138 kV bus at Limekiln to 230 kV operation in Allegheny Power
- Install a 4th Meadow Brook 500/138-kV transformer in Allegheny Power
- Install new 765/138-kV transformer bank and two new 138 kV capacitors at Amos
• New 345 kV substation called West Loop with 345 kV circuits to Crawford and Taylor
• Install two new 345/138-kV transformer banks at West Loop
• Install new 345/138-kV transformer bank at Nelson
• Install Clarendon-Ballston 230 kV line
• Install 230 kV BECO substation
• North Lancaster Reinforcement Project:
  • Re-conductor a portion of the Berks-South Akron 230 kV line
  • Establish new South Reading-South Akron 230 kV line
  • Loop South Reading-South Lebanon 230 kV line into new ring bus at Berks

Phase angle regulators (PARs) are installed on three of the four Michigan - Ontario interconnections. One PAR, on the Keith-Waterman 230 kV circuit J5D has been in service and regulating since 1975. The other two available PARs, on the Lambton-St. Clair circuits L51D and L4D, were placed in service on April 14, 2008, however, the PARs have been bypassed pending completion of agreements between the IESO, the Midwest ISO, Hydro One and International Transmission Company. The expected in service date is not known at the time of this report. The operation of the phase angle regulators will assist in the management of circulating flows. The fourth PAR, on 230 kV circuit B3N (Scott-Bunce Creek), is not expected to be available for service during the Winter Operating Period 2008-09. This PAR is located in Michigan at the Bunce Creek terminal of B3N.

**Operational Issues**

During normal operations and for typical operations planning scenarios, there may be some transmission constraints within both the PJM and MISO areas of ReliabilityFirst. All of these constraints may be alleviated with generation re-dispatch or other operating plans/procedures. ReliabilityFirst does not anticipate any significant impact on reliability from scheduled generating unit or transmission facility outages.
Historically, ReliabilityFirst has experienced widely varying power flows due to transactions and prevailing weather conditions across the region. As a result, the transmission system could become constrained during peak periods because of unit unavailability and unplanned transmission outages concurrent with large power transactions. Generation re-dispatch can be used to mitigate these potential constraints. Notwithstanding the benefits of this re-dispatch, should transmission constraint conditions occur, local operating procedures as well as the NERC transmission loading relief (TLR) procedure may also be required to maintain adequate transmission system reliability.

Certain critical flow-gates that have experienced TLRs in previous winters continue to be identified as heavily loaded in various reliability assessments and may require operator intervention to ensure reliability is maintained. No major changes have been identified that would adversely impact reliability this winter.

Both MISO and PJM do not anticipate any problems due to generation or transmission outages for the winter period. Also, there are no environmental or regulatory restrictions or unusual operating conditions expected to impact system reliability.

Reliability Assessment Analysis

Both MISO and PJM conduct seasonal operational planning studies for the transmission system. No unique operational issues were reported from the studies.

The ReliabilityFirst 2008-09 winter assessment relies on the reserve margin requirements determined for the PJM and MISO areas. Analyses were conducted by PJM and the Midwest PRSG at the end of 2007 or early in 2008 to satisfy the ReliabilityFirst Loss of Load Expectation (LOLE) criterion of not exceeding one occurrence in ten years on an annual basis. These analyses include demand forecast uncertainty, outage schedules, and other relevant factors when determining the probability of forced outages exceeding the available margin for contingencies. The assessment of PJM resource adequacy was based on reserve requirements determined from their analysis. To assess MISO resource adequacy, RFC calculated a combined reserve target based on the reserve requirement for demand in the Midwest PRSG, the remaining MRO area of MISO that uses the MAPP reserve requirement, and a small amount of other MISO demand that uses a MISO default reserve requirement. This RFC
calculated reserve target may be different than the MISO calculated reserve requirement, based on provisions in the Energy Markets Tariff.

Therefore, the assessment for the entire ReliabilityFirst regional area is derived from the results of the PJM and MISO assessments. It follows that when each RTO has adequate resources based on satisfying their respective reserve requirements, then the RFC reserves can be considered to be adequate.

It is important to note that the capacity resources identified as “certain” in this assessment have been pre-certified by either PJM or MISO as able to be utilized within their RTO market area. This means that these resources are considered to be fully deliverable within and recallable by their respective markets. Both PJM and MISO only include in the certain category those generator resources determined to satisfy their respective deliverability requirements. In both RTOs, there are additional resources identified as uncertain that may be available to serve load.

**PJM Reserve Margins**

The reserve margin requirement for the PJM RTO is 15.0% over the summer’s NID. This was determined from a study performed by the PJM planning department, reviewed by stakeholders, and approved by the PJM Board of Managers. Study criteria used in the evaluation can be found in the PJM Planning Manual M-20, “PJM Resource Adequacy Analysis”.

The installed capacity necessary to meet the PJM requirement is 156,100 MW. PJM has 159,800 MW of committed resources in this assessment. The winter reserve margin for the PJM RTO of 49,100 MW is 44.4% of the NID.

**MISO Reserve Margins**

Under the current Resource Adequacy section of the MISO’s Energy Markets Tariff (Module E), reserve margins are established by the States and NERC Regional Entities. There are two groups within the MISO that have established reserve requirements consistent with the Regional Entity standards.
The Midwest PRSG (MPRSG) has approved planning reserve requirements for three zones (East, Central, West) within the MISO Market Footprint\(^6\). MAPP also has an approved planning reserve requirement for MRO regional demand within the MISO market. A 12% default requirement is applicable to the small amount of demand not included in MAPP or the MPRSG. RFC used these applicable reserve margins in the Midwest ISO for the 2008-09 planning year to calculate a reserve target for MISO in this assessment of 14.1%.

The reserve margin target in this assessment is based on NID. The projected reserve margin for MISO is 42.2% of the NID (33,500 MW). Therefore, the reserves are adequate within the Midwest ISO since the available reserves are greater than the requirement of 11,181 MW.

**RFC Reserve Margins**

The reserve margin for Reliability\(First\) is 70,100 MW, which is 49.8% of NID. PJM and MISO each have sufficient resources to satisfy their respective reserve margin requirements. Therefore, the 49.8% calculated reserve margin this winter in the Reliability\(First\) region is adequate. This compares to a 43.3% reserve margin in last year’s assessment. While it is not essential for either PJM or MISO to have access to external resources to satisfy this winter’s reserve requirements, both RTOs utilize resources that are not within the Reliability\(First\) boundary.

**Reserve Margin Sensitivity**

For the winter of 2008-09, a higher demand forecast was used to prepare a reserve margin sensitivity for extreme weather across the Reliability\(First\) region. This high demand forecast was developed by combining the 90/10 demand forecasts of PJM and MISO with the OVEC demand and applying a coincidence factor. This is not a true 90/10 demand forecast for the Reliability\(First\) regional area. However, it is being used to evaluate sensitivity to extreme weather. This forecast amounts to a potential demand increase of about 8,300 MW in January under this weather scenario. On an NID basis, the reserve margin would be 61,800 MW or 41.4%.

While this illustrates that high demand due to extreme weather can significantly reduce the reserve margins, the projected reserve margins for this winter should be sufficient to manage additional demands due to extreme weather. As load increases due to the weather conditions, system operators closely monitor the available generator status and attempt to maintain reserves above the minimum by purchasing additional power from the Interconnection. Curtailment of the interruptible and other DSM program loads would precede a public appeal for conservation and any alerts and warnings that would be issued as reserves become lower. Such procedures are designed to minimize the potential for curtailing firm load. Although a high level of generator outages coupled with high loads from extreme weather and a lack of additional power available from the Interconnection could result in the curtailment of firm demand, such a curtailment is not expected.

Both MISO and PJM conduct comprehensive detailed generator load deliverability studies to determine that resources are deliverable to load. MISO deliverability test results can be found at http://www.midwestmarket.org/page/Generator+Interconnection under Generator Deliverability Tests. PJM tests the capability of the transmission system to deliver energy from capacity resources to the aggregate of PJM load. This generator deliverability test ensures that the transmission system is robust enough so that capacity resources will not be “bottled” under normal peak conditions. In addition to the generator deliverability tests described above, PJM also performs “load deliverability testing” to ensure that the transmission system is robust enough to deliver energy to an area of the system that is experiencing a capacity deficiency. Both the generator and load deliverability testing procedures are documented in PJM Manual 14B – PJM Region Transmission Planning Process at the following link: http://www.pjm.com/contributions/pjm-manuals/pdf/m14b.pdf.

Neither MISO nor PJM have any deliverability concerns for this assessment period.

While ReliabilityFirst reviews various sources of information for potential fuel supply issues, it is the responsibility of individual companies to coordinate with the fuel industry to ensure that supplies are adequate. When needed, ReliabilityFirst will survey its members on specific fuel related issues to determine the extent of fuel supply problems and the measures being taken by its members to mitigate any problems.

In previous years within the MISO area, fuel supply and delivery problems have had a significant impact on the available generating capacity. The main concern with coal fired generation is the delivery of coal to plants throughout the winter months. Coal
Delivery issues have been experienced in the past, but are not projected for this winter. However, it is possible that unexpected rail outages could impact the delivery of coal to generating plants. Peak storage conditions and demand for natural gas usually occur during the winter period. Currently, MISO has no concern that the present storage levels will be insufficient for winter demand. The MISO area is not currently experiencing drought conditions and reservoir levels are projected to be at average levels for this winter period. There is a low probability that water levels will create problems during winter peak conditions. PJM also does not foresee any fuel delivery problems for this winter.

ReliabilityFirst actively participates in all three of the Eastern Interconnection Reliability Assessment Group (ERAG) interregional seasonal transmission assessment efforts and also conducted its own transfer capability analyses and assessment (see http://www.rfirst.org/Reliability/ReliabilityHome.aspx). Transfer capability results are included in each of the regional and interregional seasonal reports. The inter-regional studies do not recognize limits external to the systems studied; however, ReliabilityFirst regional analyses do recognize facility constraints external to its boundary. ReliabilityFirst members also conduct their own seasonal assessments. PJM does not recognize constraints outside of the PJM footprint in its seasonal assessments. Transfer capabilities are projected to be adequate for this winter.

Through various member regional and inter-regional studies, ReliabilityFirst has not identified any transmission constraints that could significantly impact regional reliability for this winter.

Both MISO and PJM have the capability of performing small signal analysis, if needed. No small signal problems have been observed or are anticipated for this winter.

Static and dynamic reactive power studies are performed as needed by the individual transmission owner or planner for their area of responsibility. ReliabilityFirst, as a region, performs power-voltage (P-V) analyses for seasonal assessments on selected areas within its footprint. MISO and PJM also perform voltage analysis as part of their load deliverability studies. There are no dynamic or static reactive power-constrained areas that will impact PJM operations over the assessment period.
No new Under Voltage Load-Shedding (UVLS) schemes have been installed since last winter. Currently, there are two automatic under voltage load shed (UVLS) schemes within RFC. One is located in the northern Ohio/western Pennsylvania area and the other is in the northern Illinois area. These schemes have the capability to automatically shed a combined total of about 2,300 MW and provide an effective method to prevent uncontrolled loss-of-load following extreme outages in those areas. While there is some under voltage load-shedding capability installed in the PJM area, it is all for local distribution system problems.

Other Region-Specific Issues

ReliabilityFirst has no additional reliability concerns for this winter peak season.

Region Description

ReliabilityFirst currently consists of 45 Regular Members, 23 Associate Members, and 4 Adjunct Members operating within 12 NERC balancing authorities, which includes over 350 owners, users, and operators of the bulk-power system. They serve the electrical requirements of more than 72 million people in a 238,000 square-mile area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. The ReliabilityFirst area demand is primarily summer peaking. Additional details are available on the ReliabilityFirst website (http://www.rfirst.org).
### Appendix I – Winter 2008-09 Expected Load and Capacity Forecasts

#### Table 1 – NPCC Summary

<table>
<thead>
<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity MW</th>
<th>Purchases(^1) MW</th>
<th>Sales(^1) MW</th>
<th>Total Capacity(^2) MW</th>
<th>Load Forecast MW</th>
<th>Interruptible Load MW</th>
<th>Known Maint./Derat. Reserve MW</th>
<th>Reg. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
<th>Net Margin(^3) MW</th>
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#### Notes

1) Purchases and Sales represent those contracts with Areas outside of NPCC
2) Total Capacity = Installed Capacity + Purchases - Sales
3) Net Margin = Total Capacity - Load Forecast + Interruptible Load - Known maintenance - Operating reserve - Unplanned Outages
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**Notes**

Sales: 205 MW to Quebec including losses.

Purchases: Capacity backed of 98 MW from Quebec including losses.

Capacity backed of 195 MW from Quebec including losses.
### Table 3 – New England

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<th>Known Maint./Derat. MW</th>
<th>Req. Operating Reserve MW</th>
<th>Unplanned Outages MW</th>
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**Notes**

- Installed Capacity based on assumptions in ISO New England’s 2008 Regional System Plan (RSP08) and projected new generation. Also included are capacity deratings to reflect the assumption that Mystic 8 and 9 and Seabrook will be limited to a total of 1,200 MW.
- Purchases and Sales based on 2008 CELT Report
- Load Forecast assumes Peak Load Exposure reported in the 2008 CELT Report
- Interruptible Loads as reported in ISO-NE Demand Response Enrollment Statistics as of October 1, 2008
- 1,800 MW of operating reserve assumes 100% of the first largest contingency at 1,200 MW and 50% of the second largest contingency of 1,200 MW
- Includes known maintenance as of October 5, 2008
- Assumed unplanned outages based on historical observation of outages, with an additional 3,900 MW of outages for generation at risk due to gas supply during seven weeks in January and February
### Table 4 – New York

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<tr>
<th>Week Beginning Sundays</th>
<th>Installed Capacity</th>
<th>Firm Purchases</th>
<th>Firm Sales</th>
<th>Total Capacity</th>
<th>Load Forecast</th>
<th>Interruptible Load</th>
<th>Known Maint./Derat.</th>
<th>Req. Operating Reserve</th>
<th>Unplanned Outages</th>
<th>Net Margin</th>
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**Notes**

The "Purchases" column represents the net purchases/sales combined; the positive value in this column reflects a net purchase into NY of 2,802 MW.

The "Sales" column is zero reflecting a net purchase, this does not mean there are zero sales.
### Table 5 – Ontario

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<th>Installed Capacity MW</th>
<th>Firm Purchases MW</th>
<th>Firm Sales MW</th>
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<th>Interruptible Load MW</th>
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<th>Unplanned Outages MW</th>
<th>Net Margin MW</th>
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**Notes**

- Bottled capacity is included in the "Known Maintenance/Derate MW" column.
Table 6 – Québec

Control Area Load and Capacity

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<th>Week Beginning Sundays</th>
<th>Installed Capacity1</th>
<th>Firm Purchases2</th>
<th>Firm Sales3</th>
<th>Total Capacity</th>
<th>Load Forecast4</th>
<th>Interruptible Load</th>
<th>Known Maint./Derat. Reserve</th>
<th>Req. Operating Reserve</th>
<th>Unplanned Outages</th>
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Notes

1) Includes independant power producers, Alcan and available capacity of Churchill-Falls at the Newfoundland-Québec border.
2) Purchase from New-Brunswick (Millbank)
3) Sales to NE of 310 MW plus losses.
   - Sales to NB, December and March, of 100 MW plus losses.
   - Sales to NB, January and February, of 200 MW plus losses.
4) Does not include firm sale of 145 MW to Cornwall. (154 MW with losses)
5) Expected weekly internal peak load plus 154 MW for Cornwall including losses.
6) Includes 250 MW of load management through voltage reduction
Appendix II – Load and Capacity Tables definitions

This appendix defines the terms used in the Load and Capacity tables of Appendix I. Individual Balancing Authority Area particularities are presented when necessary.

Installed Capacity

This is the generation capacity installed within a Balancing Authority Area. This should correspond to nameplate and/or test data and may include temperature derating according to the Operating Period. It may also include wind generation derating.

Individual Balancing Authority Area particularities

New England

In most cases, generator capabilities are based on the results of summer and winter audits. For those generators that are affected by ambient temperature, the audit results are adjusted to reflect output at 20 °F (-6.7 °C) during the winter and 90 °F (32 °C) during the summer. Daily cycle hydro capabilities are based on an analysis that takes into consideration historical stream flow.

Québec

Both Hydro-Québec Production and Hydro-Québec Distribution provide capacity in Québec. For HQP, this includes its own generation, Churchill-Falls, Alcan contracts and private producers (hydraulic, wind, biomass, etc.). For HQD, this includes TransCanada Energy, biomass and wind generation.

Maritimes

This number is the maximum net rating for each generation facility (net of unit station service) and does not account for reductions associated with ambient temperature derating and intermittent output (e.g. hydro and/or wind).

Ontario

This number includes all generation registered with the IESO.

NPCC A-07

Capacity: The rated continuous load-carrying ability, expressed in MW or MVA of generation, transmission, or other electrical equipment.

Purchases

These are purchases between Balancing Authority Areas or from outside NPCC that have firm transmission reservations to back them up.

Individual Balancing Authority Area particularities
New England
Only long-term, capacity-backed purchases are included.

New York
NY does not use the firm transmission concept.

Québec
Both long term firm purchases and short term calls for tenders are included.

Maritimes
Short or long-term capacity-backed purchases would be included.

Ontario
Ontario only allows hourly transactions

Sales
These are sales between Balancing Authority Areas or to outside NPCC that have firm transmission reservations to back them up.

Individual Balancing Authority Area particularities

New England
Only long-term, capacity-backed sales are included.

New York
NY does not use the firm transmission concept.

Québec
Long term firm sales are included. However, in this assessment, the 145 MW contract to Cedar Rapids Transmission is not included in the sales. It is included in the Québec Balancing Area demand. This is different than what is done in the NERC seasonal assessments.

Maritimes
Short or long-term capacity-backed sales would be included.

Ontario
Ontario only allows hourly transactions.

Total Capacity
Total Capacity = Installed Capacity + Purchases – Sales.
Demand Forecast
This is the total internal demand forecast for each Balancing Authority Area as per its Demand Forecast Methodology (Appendix IV)

Interruptible Load
Loads that are interruptible under the terms specified in a contract. These may include supply and economic interruptible loads, Demand Response Programs or market-based programs.

Known Maintenance/Constraints
This is the reduction in Capacity caused by forecasted generator maintenance outages and by any additional forecasted transmission or by other constraints causing internal bottling within the Balancing Authority Area. Some Balancing Authority Areas may include wind generation derating.

Individual Balancing Authority Area particularities
New England
Known maintenance includes all planned outages as reported on the ISO-NE Annual Maintenance Schedule.

Québec
This includes scheduled generator maintenance and hydraulic as well as mechanical restrictions. It also includes wind generation derating. It may include — usually in summer — transmission constraints on the TransÉnergie system.

Maritimes
This includes scheduled generator maintenance and ambient temperature derates. It also includes wind and hydro generation derating.

Ontario
This includes generator maintenance, derating, plus generation bottling.

Required Operating Reserve
This is the minimum operating reserve on the system for each Balancing Authority Area.

NPCC A-07
Operating reserve: This is the sum of ten-minute and thirty-minute reserve (fully available in 10 minutes and in 30 minutes).
Individual Balancing Authority Area particularities

New England
The required operating reserve consists of 100% of the first largest contingency plus 50% of the second largest contingency.

Québec
The required operating reserve consists of 100% of the largest first contingency + 50% of the largest second contingency, including 1,000 MW of hydraulic synchronous reserve distributed all over the system to be used as stability and frequency support reserve. The total reserve requirement is 1,500 MW.

Maritimes
The required operating reserve consists of 100% of the first largest contingency plus 50% of the second largest contingency.

Ontario
The required operating reserve consists of 100% of the first largest contingency plus 50% of the second largest contingency.

Unplanned Outages
This is the forecasted reduction in Installed Capacity by each Balancing Authority Area based on historical conditions used to take into account a certain probability that some capacity may be on forced outage.

Individual Balancing Authority Area particularities

New England
Monthly unplanned outage values have been calculated based on five years of historical unplanned outage data.

Québec
This value includes a provision for Load Forecast uncertainty and a provision for unplanned outages, based on historic conditions.

Maritimes
Monthly unplanned outage values have been calculated based on historical unplanned outage data.

Ontario
This value is a historical observation of the capacity that is unforced outage at any given time.
**Net Margin**

Net margin = Total capacity – Load forecast + Interruptible load – Known maintenance/Constraints – Required operating reserve – Unplanned outages

**Bottled Resources**

Bottled resources = Québec Net margin + Maritimes Net margin – available transfer capacity between Québec/Maritimes and Rest of NPCC.

This is used only in summer. It takes into account the fact that the margin available in Maritimes and Québec exceeds the transfer capability to the rest of NPCC since Québec and Maritimes are winter peaking. This is calculated in Table 7 of the Summer Assessment.

**Revised net margin (NPCC Summary only)**

Revised net margin = Net margin – Bottled resources

This is used only in the Summer Assessment and follows from the Bottled Resources calculation.
Appendix III – Summary of Normal and Expected Feasible Transfer Capability under Winter Peak Conditions

The following table shows Normal Transfer Capability (NTC) between Balancing Authority Areas representing transfer capabilities under normal system conditions. It is recognized that the actual transfer conditions may differ depending on system conditions or configurations such as actual voltage profiles, operating conditions, etc. Also, the Feasible Transfer Capability (FTC) values represent an expected transfer capability under the peak demand scenario with the assumed transmission configuration identified in this report. This Feasible Transfer Capability is based on historical operating experience and known operating constraints in each Balancing Authority Area. The total for each Balancing Authority Area represents the simultaneous transfer between Balancing Authority Areas that may be achievable. It should be noted that real-time transfer limits may change depending on the operation of the system at the time and readers are encouraged to review information on the Available Transfer Capability (ATC) and Total Transfer Capabilities (TTC) between Balancing Authority Areas, via http://www.nerro.org/
Balancing Authority Area Acronym Description

<table>
<thead>
<tr>
<th>Maritimes</th>
<th>NE</th>
<th>North-East Sub-Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>NB</td>
<td>NB</td>
<td>New Brunswick</td>
</tr>
<tr>
<td></td>
<td>Ottawa</td>
<td>- Ottawa</td>
</tr>
<tr>
<td></td>
<td>East</td>
<td>- East</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>New England</th>
<th>RFC</th>
<th>ReliabilityFirst Corporation</th>
</tr>
</thead>
<tbody>
<tr>
<td>BHE</td>
<td>BHE</td>
<td>Bangor-Hydro Electric</td>
</tr>
<tr>
<td></td>
<td>MAN</td>
<td>- Manitoba</td>
</tr>
<tr>
<td>CMA</td>
<td>CMA</td>
<td>Central Massachusetts</td>
</tr>
<tr>
<td></td>
<td>MRO</td>
<td>- Midwest Reliability Organization</td>
</tr>
<tr>
<td>VT</td>
<td>VT</td>
<td>Vermont</td>
</tr>
<tr>
<td>WMA</td>
<td>WMA</td>
<td>Western Massachusetts</td>
</tr>
<tr>
<td>CT</td>
<td>CT</td>
<td>Connecticut</td>
</tr>
<tr>
<td>NOR</td>
<td>NOR</td>
<td>Norwalk</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>New York</th>
<th>Québec</th>
<th>Chateauguay</th>
</tr>
</thead>
<tbody>
<tr>
<td>NW</td>
<td>NW</td>
<td>North West Sub-Area</td>
</tr>
<tr>
<td>West</td>
<td>West</td>
<td>Western Sub-Area</td>
</tr>
<tr>
<td>Niagara</td>
<td>Niagara</td>
<td>- Niagara</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ontario</th>
<th>CHAT</th>
<th>- Chateauguay</th>
</tr>
</thead>
<tbody>
<tr>
<td>NW</td>
<td>BDF</td>
<td>Bedford/Stanstead</td>
</tr>
<tr>
<td>West</td>
<td>CRT</td>
<td>Cedar Rapids</td>
</tr>
<tr>
<td></td>
<td>CRT</td>
<td>- Transmission</td>
</tr>
<tr>
<td></td>
<td>BDF-STS</td>
<td>- Bedford/Stanstead</td>
</tr>
<tr>
<td></td>
<td>BEAU</td>
<td>Beauharnois</td>
</tr>
<tr>
<td></td>
<td>NIC</td>
<td>- Nicolet</td>
</tr>
<tr>
<td></td>
<td>MTP-MDW</td>
<td>- Matapedia-Madawaska</td>
</tr>
</tbody>
</table>

The New York Balancing Authority Area is divided into 11 zones (A – K) that are defined based on the transmission system topology.
## Transfers from Maritimes to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>NTC at Interconnection Points (MW)</th>
<th>FTC under Peak Conditions (MW)</th>
<th>Rationale for Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NB / MTP – MDW Lines 2101, 2102 (HQ), lines 3008, 3010 (NB) Lines 3012, 3113, 3114 (NB)</td>
<td>770</td>
<td>770</td>
<td>Eel River HVDC winter rating is 350 MW. Madawaska HVDC winter rating is 435 MW. The revised values are due to loss allocation. Previously the TTCs were calculated as though each HVDC station was on the provincial border when in fact they are located further within each of the Balancing Authority Areas.</td>
</tr>
<tr>
<td>Total</td>
<td>770</td>
<td>770</td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NB / BHE</td>
<td>1000</td>
<td>1000</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>1000</td>
<td>1000</td>
<td></td>
</tr>
</tbody>
</table>
## Transfers from New England to Interconnection Points

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>NTC at Interconnection Points (MW)</th>
<th>FTC under Peak Conditions (MW)</th>
<th>Rationale for Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maritimes</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BHE / NB</td>
<td>400</td>
<td>400</td>
<td>Transfer capability is dependent upon operating conditions in northern Maine. If key generation or capacitor banks are not operational, the transfer from New England to New Brunswick will be decreased.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>400</td>
<td>400</td>
<td></td>
</tr>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>VT / D</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WMA / F</td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CT / G</td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOR / K</td>
<td>286</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Sub Total</strong></td>
<td>1886</td>
<td>1,325</td>
<td>Feasible Simultaneous Transfer to New York excluding Cross Sound Cable. This is assumed to be the TTC as of Nov. 17 2006. ISO-NE planning assumptions are based on an interface limit of 900 MW, as reported in the 2006 Regional System Plan.</td>
</tr>
<tr>
<td>CT (CSC) / K</td>
<td>330</td>
<td>330</td>
<td>The transfer capability of the Cross Sound Cable is 346 MW. However, losses reduce the amount of MWs that can actually be delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal. The Cross Sound Cable is a DC tie and is not included in the Feasible simultaneous transfer capability with NY.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,216</td>
<td>1,655</td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CMA / NIC HVDC link</td>
<td>1,700</td>
<td>0</td>
<td>Phase 2 is required for internal Québec transmission needs at the time of peak. Capability of the facility is 2,000 MW; conditions in HQ limit the capability to 1,700 MW (First contingency loss of generation) at peak; conditions in NE, NY &amp; PJM may limit to 1,200 MW or less.</td>
</tr>
<tr>
<td>Highgate (VT) – Bedford (BDF) Line 1429</td>
<td>170</td>
<td>0</td>
<td>Capability of the facility is 220 MW; conditions in Vermont limit the capability to 100 MW or less. The DOE permit is 170 MW. When the delivery from Québec to NE at Highgate is zero, it is expected that the delivery to Québec from NE will be zero due to transmission limitations in New England.</td>
</tr>
<tr>
<td>Derby (VT) – Stanstead (STS) Line 1400</td>
<td>0</td>
<td>0</td>
<td>There is no capability to export to Québec through this interconnection.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,870</td>
<td>0</td>
<td>The New England to Québec transfer limit at peak load is assumed to be 0 MW. It should be noted that this limit is dependant on New England generation and could be increased up to approximately 350 MW depending on New England dispatch. If energy was needed in Québec and the generation could be secured in the Real-Time market, this action could be taken to increase the transfer limit.</td>
</tr>
</tbody>
</table>
### Transfers from New York to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>NTC at Interconnection Points (MW)</th>
<th>FTC under Peak Conditions (MW)</th>
<th>Rationale for Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D / VT</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>F / WMA</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>K / CT</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>K / NOR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Sub Total</strong></td>
<td>1,450</td>
<td>1,450</td>
<td>Feasible Simultaneous Transfer to New England excluding Cross Sound Cable.</td>
</tr>
<tr>
<td>K / CT (CSC)</td>
<td>330</td>
<td>330</td>
<td>Cross Sound Cable power injection is up to 346 MW; losses reduce power at the point of withdrawal to 330 MW. The Cross Sound Cable is a DC tie and is not included in the Feasible Simultaneous Transfer capability with NY.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,780</td>
<td>1,780</td>
<td></td>
</tr>
<tr>
<td>Ontario</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D / East Lines L33P, L34P</td>
<td>400</td>
<td>400</td>
<td></td>
</tr>
<tr>
<td>A / Niagara Lines PA301, PA302, BP76, PA27</td>
<td>1,350</td>
<td>1,350</td>
<td>Simultaneous transfers between New York and Ontario may be impacted by loop flows assuming instructions to use the phase shifter capability of the Michigan – Ontario Interface is not available. Additionally, thermal limits on the QFW interface may restrict imports to lesser values when the generation in the Niagara area is taken into account. BP76 O/S.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,750</td>
<td>1,750</td>
<td></td>
</tr>
<tr>
<td>PJM</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A / PJM</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C / PJM</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>G / PJM</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>J / PJM</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,650</td>
<td>2,650</td>
<td>Feasible Simultaneous Transfer to PJM on peak.</td>
</tr>
<tr>
<td>Québec</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D / Chat; L7040</td>
<td>1,000</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>D / CRT Lines CD11, CD22</td>
<td>100</td>
<td>100</td>
<td>Through Variable Frequency Transformer (VFT) in Langlois Substation, Québec.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,100</td>
<td>1,100</td>
<td></td>
</tr>
</tbody>
</table>
## Transfers from Ontario to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>NTC at Interconnection Points (MW)</th>
<th>FTC under Peak Conditions (MW)</th>
<th>Rationale for Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East / D Lines L33P, L34P</td>
<td>300</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>Niagara / A Lines PA301, PA302, BP76, PA27</td>
<td>1420</td>
<td>1420</td>
<td>Simultaneous Transfers between NY and Ontario may be impacted by loop flows and assumes phase shifting capability of MECS interface is not available. BP76 is O/S.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1720</td>
<td>1720</td>
<td></td>
</tr>
<tr>
<td><strong>MISO Michigan</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines L4D, L51D, J5D, B3N</td>
<td>2330</td>
<td>2330</td>
<td>Simultaneous Transfers between Michigan and Ontario may be impacted by loop flows and assumes phase shifting capability of Ontario-Michigan interface is not available.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2330</td>
<td>2330</td>
<td></td>
</tr>
<tr>
<td><strong>Québec</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NE / RPD – KPW Lines D4Z, H4Z</td>
<td>110</td>
<td>85</td>
<td>Tie line facilities are thermally restricted.</td>
</tr>
<tr>
<td>Ottawa / BRY – PGN Lines X2Y, Q4C</td>
<td>120</td>
<td>32</td>
<td>Circuit Q4C is capable of 120 MW less ⅓ of Chat Falls that is considered in the Québec Installed Capacity (120-88=32)</td>
</tr>
<tr>
<td>Ottawa / Brookfield Lines D5A, H9A</td>
<td>200</td>
<td>115</td>
<td>Only One of H9A or D5A can be in services at any time. The transfer capability reflects usage of DSA.</td>
</tr>
<tr>
<td>East / Beau Lines B5D, B31L</td>
<td>470</td>
<td>470</td>
<td>Capacity from Saunders that can be synchronized to the Hydro-Québec system.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>900</td>
<td>702</td>
<td></td>
</tr>
<tr>
<td><strong>MISO Manitoba, Minnesota</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NW / MAN Lines K21W, K22W</td>
<td>300</td>
<td>275</td>
<td></td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>140</td>
<td>140</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>440</td>
<td>415</td>
<td>Feasible Simultaneous Transfer to MAPP.</td>
</tr>
</tbody>
</table>
## Transfers from Québec to

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>NTC at Interconnection Points (MW)</th>
<th>FTC under Peak Conditions (MW)</th>
<th>Rationale for Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maritimes</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MTP-MDW / NB Lines 2101, 2102 (HQ), lines 3008, 3010 (NB) Lines 3012, 3113, 3114 (NB)</td>
<td>1,100</td>
<td>1,100</td>
<td>Eel River HVDC winter rating is 350 MW. Madawaska HVDC winter rating is 435 MW. Approximately 300 MW of radial load in New-Brunswick can be connected to Québec.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,100</td>
<td>1,100</td>
<td></td>
</tr>
<tr>
<td><strong>New England</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NIC / CMA HVDC link</td>
<td>2,000</td>
<td>1,400</td>
<td>Capability of the facility is 2,000 MW; actual conditions in NE, NY, PJM may lower this value. The value estimated at peak load is 1,400 MW.</td>
</tr>
<tr>
<td>Bedford (BDF) – Highgate (VT) Line 1429</td>
<td>220</td>
<td>200</td>
<td>Limitations on the Québec system under peak load conditions.</td>
</tr>
<tr>
<td>Stanstead (STS) – Derby (VT) Line 1400</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,270</td>
<td>1,650</td>
<td></td>
</tr>
<tr>
<td><strong>New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chateauguay – D Line 7040</td>
<td>1,500</td>
<td>615</td>
<td>Limitations on the Québec System under peak load conditions.</td>
</tr>
<tr>
<td>CRT – D Lines CD11, CD22</td>
<td>325</td>
<td>180</td>
<td>Transfer limit is 325 MW less projected peak Cornwall load of 145 MW tapped off the circuit.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,825</td>
<td>795</td>
<td>Québec to New York transfer capability may reach 2,000 MW on an hour-ahead basis and depending on operating conditions in New York and in Québec.</td>
</tr>
<tr>
<td><strong>Ontario</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RPD-KPW / NE Lines D4Z, H4Z</td>
<td>85</td>
<td>85</td>
<td></td>
</tr>
<tr>
<td>BRY-PGN / Ottawa Lines X2Y, P33C</td>
<td>410</td>
<td>232</td>
<td>Limitations on the Québec System under peak load conditions restrict deliveries as follows P33C - 167 MW and X2Y – 65 MW.</td>
</tr>
<tr>
<td>Brascan – Ottawa Lines D5A, H9A</td>
<td>235</td>
<td>235</td>
<td>Only One of H9A or D5A can be in services at any time. The transfer capability reflects usage of D5A.</td>
</tr>
</tbody>
</table>
Note: Limitations on the Québec system under peak load conditions may be due to resource limitations as opposed to transmission limitations, so that the Feasible Transfer Capability does not necessarily correspond to the TTCs published elsewhere.
## Transfers from Regions External to NPCC

<table>
<thead>
<tr>
<th>Interconnection Point</th>
<th>Normal Transfer Capability at Interconnection Points (MW)</th>
<th>Feasible Transfer Capability under Peak Conditions (MW)</th>
<th>Rationale for Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MISO / ONT</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lines L4D, L51D, J5D, B3N</td>
<td>1,930</td>
<td>1,930</td>
<td>Represents a worst case scenario for the implementation of Policy on operation.</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,930</td>
<td>1,930</td>
<td>Simultaneous Transfers between Michigan and Ontario may be impacted by loop flows and assumes phase shifting capability of MECS interface is not available.</td>
</tr>
<tr>
<td><strong>MISO / ONT</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NW / MAN Lines K21W, K22W</td>
<td>300</td>
<td>275</td>
<td></td>
</tr>
<tr>
<td>NW / MIN Line F3M</td>
<td>90</td>
<td>90</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>390</td>
<td>365</td>
<td>Feasible Simultaneous Transfer to Ontario.</td>
</tr>
<tr>
<td><strong>PJM / New York</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A</td>
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<td>C</td>
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<td>G</td>
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</tr>
<tr>
<td>J</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>3,000</td>
<td>3,000</td>
<td>Feasible Simultaneous Transfer to New York.</td>
</tr>
</tbody>
</table>
Appendix IV – Demand Forecast Methodology

Balancing Authority Area Methodologies

Maritimes
The Maritimes demand is the mathematical sum of the forecasted weekly peak demands of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes demand included a coincidence factor, the forecast demand would be approximately 1-3% lower.

For the NBSO, the demand forecast is based on an End-use Model (sum of forecasted loads by use e.g. water heating, space heating, lighting etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average.

For Nova Scotia, the demand forecast is based on a 10-year weather average measured at the major load center, along with analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

For Prince Edward Island, the demand forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecasted annual peak. The remaining months are prorated on the previous year.

The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future demands.

New England
The short-run energy model is an annual model of ISO-NE Area total energy per household, using real income per household and the real price of electricity as drivers. Households and income are proxies for all economic activity. The model output is multiplied by New England households to obtain the annual forecast of total energy.

The winter peak forecast is based on a model that relates daily peak demands (from 1992 to the most recent winter) to: the temperature at the time of the daily peak; a heating load index that captures the change in peak load response to weather over time; and a heating base load index that captures the change in peak load response to
energy (and therefore economic and demographic factors). A distribution of seasonal peaks is created based on over 35 years of weather data.

The reference demand forecast, which has a 50% chance of being exceeded, is based on weekly weather distributions. The weekly weather distributions were built using 30 years of temperature data at the time of daily electrical peaks (for non-holiday weekdays). While this temperature sampling is used to project temperature sensitive loads, a complete process of sampling and econometric models is used to project the overall aggregate electrical demand. A reasonable approximation for “normal weather” associated with this projection is 6.8 °F (-14 °C). At these forecasted load levels, a one degree Fahrenheit decrease in the temperature will result in approximately 150 MW of additional load.

A series of winter regressions (for each year from 1992 to the most recent winter) of non-holiday weekday daily peak loads and weather at the time of the peaks are used to calculate an index called the Heating Load Index (HLI), which represents the weather sensitive load and an index called the Heating Base Load Index (H-BLI) which represents the base load. The slope of the regression is the system response to weather or heating load and the intercept is the non-weather sensitive portion or base load. These annual slopes and intercepts are indexed to 1992 to create the HLI and H-BLI.

To forecast the growth in heating load, which is one of the inputs to the Short-Run Forecast model, the HLI is smoothed out to eliminate fluctuations by creating a trend value through the actual values. The forecasted portion of the HLI is the extension of that trend.

The Heating Base Load Index is also smoothed by trending the historical period. The trend is linked to the percentage growth rates of the Short-Run Energy Forecast. This ties the growth in base load to the forecasted growth of energy for the two-year period of the Short-Run Forecast.

**New York**

The NYISO uses a weather index that relates dry bulb air temperature and wind speed to the load response in the determination of the forecast. At the forecast load levels, a one-degree decrease in this index will result in approximately 100 MW of additional load. The expected temperature at which the New York load could reach the forecast peak is 12.9 °F (-11 °C).

**Ontario**

The Ontario Demand is the sum of coincident loads plus the losses on the IESO-controlled grid. Ontario Demand is calculated by taking the sum of injections by registered generators, plus the imports into Ontario, minus the exports from Ontario.
Ontario Demand does not include loads that are supplied by non-registered generation. The IESO forecasting system uses multivariate econometric equations to estimate the relationships between electricity demand and a number of drivers. These drivers include weather effects, economic data and calendar variables. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, including zone and system wide projections. IESO produces a forecast of hourly demand by zone. From this forecast the following information is available:

- hourly peak demand;
- hourly minimum demand;
- hourly coincident and non-coincident peak demand by zone;
- energy demand by zone.

These forecasts are generated based on a set of weather and economic assumptions. IESO uses a number of different weather scenarios to forecast demand. The appropriate weather scenarios are determined by the purpose and underlying assumptions of the analysis. The base case demand forecast uses a median economic forecast and monthly normalized weather. Multiple economic scenarios are only used in longer term assessments. A quantity of price-responsive demand is also forecast based on market participant information and actual market experience.

Québec

The Hydro-Québec demand and energy-sales forecasting is Hydro-Québec Distribution’s responsibility. First, the energy-sales forecast is built on the forecast from four different consumption sectors — domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector. Basically, they are analytical models based on an end-use approach and/or econometric modeling. They rely greatly on economic-driver forecasts, demographics, consumption analysis, individual short-term forecasts of large industrial customers and various surveys. This forecast is normalized for weather conditions based on a 36-year historical analysis.

The annual energy requirements are obtained by adding transmission and distribution losses to the various end-use consumption forecasts. A monthly breakdown is then obtained by applying distribution rates to the annual energy requirements. Each end-use’s monthly peak demand is then calculated using load factors. The sum of these monthly end-use peak demands is the total monthly peak demand.

In relation to peak demand uncertainty and variability due to weather and/or other conditions, Hydro-Québec has developed hourly chronological load profiles based on a 36-year analysis of historical weather conditions (1971-2006). This methodology is
useful to quantify weather uncertainty and its impacts on peak demand. Since Québec has a winter peaking load profile, the uncertainty – measured by a standard deviation analysis – is lower during the summer than during the winter. As an example, at the summer peak, weather conditions uncertainty is about 300 MW, equivalent to one standard deviation. During winter, this uncertainty is 1,200 MW. Extreme weather deviations can be quantified at about 1,100 MW for the summer peak and at about 4,400 MW for the winter peak.

TransÉnergie — the Québec system operator — then determines the Québec Balancing Authority Area forecasts using Hydro-Québec Distribution’s forecasts (HQ demand) and adding the demands of independent systems and the agreements with different private systems within the Balancing Authority Area. The forecasts are updated on an hourly basis, within a 12-day horizon according to information on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority Area. TransÉnergie has a team of meteorologists who feed the demand forecasting model with accurate climatic observations and precise weather forecasts. Short term changes in industrial loads and agreements with different private systems within the Balancing Authority Area are also taken into account on a short term basis.
Appendix V - NPCC Operational Directories, Criteria, and Procedures

NPCC Regional Reference Directory #2 - Emergency Operations

Description: Objectives, principles and requirements are presented to assist the NPCC Balancing Authority Areas in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency.

NPCC Regional Reference Directory #8 - System Restoration

Description: This directory provides objectives, principles and requirements to enable each NPCC Balancing Authority Area to perform power system restoration following a major or total blackout.

A-02 Basic Criteria for Design and Operation of Interconnected Power Systems

Description: This Criterion establishes the basic principles and requirements for the design and the operation of the NPCC bulk power system.

Note- Developing Directory #1 to replace the existing A-02.

A-03 Emergency Operation Criteria

Description: Objectives, principles and requirements are presented to assist the NPCC Balancing Authority Areas in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency.

Note- Directories #2 and #8 have been developed and replaced Document A-03 on October 21, 2008.

A-06 Operating Reserve Criteria

Description: This Criterion establishes standard terminology and minimum requirements governing the amount, availability and distribution of operating reserve. Procedures are included for corrective action and mutual assistance in case of operating reserve shortages. The objective is to ensure a high level of reliability in the NPCC Region that is, as a minimum, consistent with the standards specified by the North American Electric Reliability Corporation (NERC). (The A-6 Document completed the posting period in NPCC Open Process and was approved by the NPCC Reliability Coordinating Committee on November 19, 2008 to be sent to the NPCC membership for final approval.)

Note- Developing Directory #5 to replace the existing A-06.

A-10 Classification of Bulk Power System Elements
Description: The NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) and related criteria documents define specific requirements applicable to design, operation, and protection of the bulk power system. This Classification of Bulk Power System Elements (Document A-10) provides the methodology for the identification of those elements of the interconnected NPCC Region to which NPCC bulk power system criteria are applicable. Each Balancing Authority Area has an existing list of bulk power system elements. The methodology in this document is used to classify elements of the bulk power system and has been applied in classifying elements in each Balancing Authority Area as bulk power system or non-bulk power system.

A-13 NPCC Verification of Generator Gross and Net Real Power Capability (The current A-13 Document was approved in July 2007. A revised version was approved by the NPCC Reliability Coordinating Committee in March 2008 but is being held in abeyance pending approval of Directory #9 for determining real capabilities of generators)

Description: This document establishes the minimum criteria to verify the Gross Real Power Capability and Net Real Power Capability of generators used to ensure accuracy of information used in the steady-state and dynamic simulation models to assess the reliability of the NPCC bulk power system. These criteria have been developed to ensure that the requirements specified in NERC Standard MOD-024-1, “Verification of Generator Gross and Net Real Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC standards.

Note- Directory #9 was developed to replace the existing A-13 and was approved by the NPCC Reliability Coordinating Committee on November 19, 2008 to be sent to the NPCC membership for final approval.

A-14 NPCC Verification of Generator Gross and Net Reactive Power Capability (Approved by the NPCC Reliability Coordinating Committee in March 2008 but is being held in abeyance pending approval of a directory for determining reactive capabilities of generators—“Directory #10”)

Description: This document establishes the minimum criteria to verify the Gross Reactive Power Capability and Net Real Power Capability of generators used to ensure accuracy of information used in the steady-state and dynamic simulation models to assess the reliability of the NPCC bulk power system. These criteria have been developed to ensure that the requirements specified in NERC Standard MOD-025-1, “Verification of Generator Gross and Net Reactive Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC standards.

Note- Directory #10 was developed to replace the existing A-14 and was approved by the Reliability Coordinating Committee on November 19, 2008 to be sent to the NPCC membership for final approval.

B-13 Guide for Reporting System Disturbances (this document has been retired and replaced by the C-42 document)
B-20  Guidelines for Identifying Key Facilities and Their Critical Components for System Restoration”

Description: Establishes requirements and guidelines for the identification of Key Facilities and their Critical Components that are required for restoration of the power system following a partial or total system blackout.

C-01  NPCC Emergency Preparedness Conference Call Procedures-NPCC Security Conference Call Procedures

C-04  Monitoring Procedures for Guidelines for Inter-Area Voltage Control

Description: This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC's Procedure for Inter-AREA Voltage Control (Document C-40).

C-05  Monitoring Procedures for Emergency Operation Criteria

Description: This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC's Emergency Operation Criteria (Document A-3).

C-07  Monitoring Procedures for Guide for Rating Generating Capability

Description: This procedural document establishes the TFCO's monitoring and reporting requirements for conformance with the NPCC, Guide for Rating Generating Capability (Document B-9).

C-08  Monitoring Procedures for Control Performance Guide During Normal Conditions

Description: This procedural document establishes a performance measure for NPCC Balancing Authority Areas and systems and outlines the reporting function for NPCC Control Performance Guide During Normal Conditions (Document B-2).

C-09  Monitoring Procedures for Operating Reserve Criteria

Description: This procedural document establishes the TFCO's monitoring and reporting requirements for conformance with the NPCC Operating Reserve Criteria (Document A-6).

C-11  Monitoring Procedures for Interconnected System Frequency Response

Description: This procedural document defines procedures for monitoring frequency responses to large generation losses.

C-12  Procedures for Shared Activation of Ten Minute Reserve
Description: This procedural document outlines procedures to share the activation of ten-minute reserve on a Balancing Authority Area basis. The methods prescribed by the procedure are intended to ensure that lost generation or energy purchases are quickly replaced by several areas simultaneously loading generation in the few minutes immediately following a loss.

C-13 Operational Planning Coordination (presently under revision)

Appendix D - NPCC Critical Facilities List

Description: This document coordinates the notification of planned facility outages among the Balancing Authority Areas. It also establishes formal procedures for Balancing Authority Area communications in advance of a period of likely capacity shortages as well as for weekly and emergency NPCC conference call among the Balancing Authority Areas.

C-15 Procedures for Solar Magnetic Disturbances on Electrical Power Systems

Description: This procedural document clarifies the reporting channels and information available to the operator during solar alerts and suggests measures that may be taken to mitigate the impact of a solar magnetic disturbance.

C-17 Procedures for Monitoring and Reporting Critical Operating Tool Failures

The purpose of this document is to outline the reporting requirements, responsibilities and obligations of the NPCC Reliability Coordinators (RC’s) in response to unforeseen critical operating tool failures.

C-20 Procedures during Abnormal Operating Conditions

Description: This procedure is intended to complement the Emergency Operation Criteria (Document A-3) by providing specific instructions to the System Operator during such conditions in an NPCC Balancing Authority Area or Balancing Authority Areas.

C-35 NPCC Inter-Area Power System Restoration Reference Document

Description: This procedure provides guidance and training material to the system operator to manage system restoration events that affect the NPCC Balancing Authority Areas and adjoining Balancing Authority Areas.

C-36 Procedures for Communications during Emergencies

Description: This procedure establishes the types of communications that should take place between Balancing Authority Area system operators and with external agencies during an emergency. It also indicates the data that should be collected during and after a major system event.
C-37  Operating Procedures for ACE diversity Interchange

Description: This document establishes a procedure, ACE Diversity Interchange, with which participating Balancing Authority Areas can achieve a mutual reduction in regulation requirements and generator output adjustments.

C-38  Procedure for Operating Reserve Assistance

Description: This procedure allows NPCC Balancing Authority Areas except Hydro-Québec to share resources to meet operating reserve requirements. This procedure enables Balancing Authority Areas to assist each other in meeting their ten minute reserve requirement.

C-40  Procedures for Inter-AREA Voltage Control

Description: This Procedure provides general principles and guidance for effective inter-AREA voltage control, consistent with the NPCC, Inc. Document A-02, “Basic Criteria for Design and Operation of Interconnected Power Systems,” and applicable NERC Standards. Specific methods to implement this Procedure may vary among Balancing Authority Areas, depending on local requirements. Coordinated inter-AREA voltage control is necessary to regulate voltages to prevent equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the network and lessens equipment degradation. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent Balancing Authority Areas can assist each other to compensate for deficiencies or excesses of reactive power and improve voltage profiles and system security.

C-42  Procedure for Reporting and Reviewing System Disturbances

This document establishes the procedures of the Task Force on Coordination of Operation (TFCO) for reporting and reviewing system disturbances.

C-43  NPCC Operational Review for the Integration of New Facilities

The document provides the procedure to be followed in conducting operations reviews of new facilities being added to the power system. This procedure is intended to apply to new facilities that, if removed from service, may have a significant, direct or indirect impact on another Reliability Coordinator Area’s inter-AREA or intra-AREA transfer capabilities. The cause of such impact might include stability, voltage, and/or thermal considerations.

C-44  NPCC, Inc. Regional Methodology and Procedures for Forecasting TTC and ATC

Description: This document establishes a common methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) within the NPCC Region.
CO-12 Seasonal Assessment Methodology

The documents provides the procedure used and schedules followed by the CO-12 Working Group in conducting the overall assessments of the reliability of the generation and transmission system in the NPCC Region for the Summer Operating Period (defined as the months of May through September) and Winter Operating Period (defined as the months of December through March). (The C-45 Document is presently in NPCC Open Process until November 17, 2008 and final approval by the Task Force on Coordination of Operation is anticipated in early 2009.)
Appendix VI - Web Sites

Independent Electricity System Operator
http://www.ieso.ca/

ISO- New England
http://www.iso-ne.com

Lake Erie Emergency Re-dispatch
http://www.npcc.org/interReg/LEER.aspx

MAPP
http://www.mappcor.org/

Maritimes
Maritimes Electric Company Ltd.
http://www.maritimeelectric.com

New Brunswick System Operator
http://www.nbso.ca/

Nova Scotia Power Inc.
http://www.nspower.ca/

Northern Maine Independent System Administrator
http://www.nmisa.com

Midwest Reliability Organization
www.midwestreliability.org

National Oceanic and Atmospheric Administration Solar Cycle Sunspots
http://www.swpc.noaa.gov/SolarCycle/

New York ISO
http://www.nyiso.com/
Northeast Power Coordinating Council, Inc.
   http://www.npcc.org/

North American Electric Reliability Corporation
   http://www.nerc.com

ReliabilityFirst Corporation
   http://www.rfirst.org

TransÉnergie

Drought Predictors

  Canada
   http://gfx.weatheroffice.ec.gc.ca/saisons/

  United States
   http://www.drought.unl.edu/dm/index.html
Appendix VII - References

NPCC Multi-Area Probabilistic Reliability Assessment for Winter 2008-09 – November 2008

NPCC Reliability Assessment for Winter 2007-08 - November 2007